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**EL DORADO MICELLAR-POLYMER DEMONSTRATION PROJECT
SECOND ANNUAL REPORT, JULY 1975-MAY 1976**

By

Cities Service Oil Co.
Prepared for ERDA Under Contract No. E(34-1)-0003

Date Published—November 1976

MASTER

Bartlesville Energy Research Center
Energy Research and Development Administration
Bartlesville, Oklahoma

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By

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Cities Service Oil Company
July 1976

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Administration Under Contract No. E(34-1)-0003

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SUMMARY

The El Dorado Micellar-Polymer Demonstration Project is a cooperative venture between Cities Service Oil Company and the United States Energy Research and Development Administration (ERDA). The project is governed by ERDA Contract Number E(34-1)-0003 (formerly, Contract Number H0242035). The primary objectives of this project are to determine the economic feasibility of improved oil recovery using two micellar-polymer processes and to determine the associated benefits and problems of each process. The El Dorado Demonstration Project is designed to allow a side-by-side comparison of two distinct micellar-polymer processes in the same field so that the reservoir conditions for the two floods are as nearly alike as possible.

This report covers research and field work on the El Dorado Project during the second project year--July, 1975, to May, 1976. Project activities prior to this period were reported in the First Annual Report.

Laboratory oil displacement tests were conducted using Shell Oil Company and Union Oil Company chemical formulations in both Berea and El Dorado Admire Sandstone cores. In short Admire cores (ten inches long) the residual oil saturation after chemical flooding ranged from 12 to 22 pore volume percent. However, it was demonstrated using Berea cores that the residual oil saturation after chemical flooding can be reduced by an additional ten pore volume percent by running tests on four-foot instead of ten-inch cores. Consequently, more testing has been initiated using long cores composed of stacked Admire Sandstone plugs.

Total relative mobility of the oil-water bank created during chemical flooding was measured in Admire Sandstone cores. The values ranged from 0.018 to 0.065 reciprocal centipoise. These values confirm the total relative mobilities calculated from relative permeability tests. Laboratory results were subsequently used in a numerical reservoir simulator to check the validity of the polymer slug design suggested by one of the process vendors.

Four observation wells were drilled, cored, and logged during the year. They were cased with fiberglass and are now being used to monitor fluid properties. Fluid samples are taken daily from perforations spanning a one-foot interval. The wells are being logged with induction tools as significant changes in salinity are detected in the fluid samples.

A tracer test was conducted by injection of chemical tracers into each of the 18 injection wells. No chemical tracer was detected in any of the production or observation wells; this indicates that there is no gross channeling in the reservoir. The same conclusion was drawn from results of interference tests.

Pressure transient tests were conducted on the pattern wells. Interference test results showed less permeability contrast when injectors and producers are aligned in a northeast-southwest and northwest-southeast direction rather than in a north-south and east-west direction. This information was essential in selecting the pattern orientation. Other factors that were taken into consideration in selecting the 6.4 acre five-spot pattern array were economics, scale-up problems, and project timing. Pressure transient test results were also used to select individual wells for stimulation prior to the start of injection.

Performance forecasting was utilized to show that maintaining the bottom-hole injection pressures at 400 psia and the producing pressures at

30 psia would increase throughput rates and result in acceptable project life for the 6.4 acre five-spot patterns. Injection well rates relative to the central injector were computed. These rates will be used as a guide for the operation of injection wells. This plan corresponds to operation at constant bottom-hole pressures for a homogeneous reservoir of uniform thickness.

Construction of the fresh water system and injection plant was completed. The injection plant has performed satisfactorily.

Injection of pretreatment fluid was started in both patterns on November 18, 1975. Severe loss of injectivity was experienced during the first week of injection. Several likely causes were identified and corrective actions taken. More moderate injectivity problems have continued throughout this reporting period. Additional preventive measures have been undertaken to improve the quality of injected fluids. A procedure was developed to stimulate and clean-up wells damaged by the injection fluid. A preliminary evaluation indicates that combination solvent-acid treatments will increase injection rates to the desired level.

An injectivity test using the complete sequence of fluids (pre-flush, surfactant, polymer solution, and drive water) recommended by Shell will be completed during the coming year. This test will be similar to the test conducted on well MP-104 during the summer of 1974. Injection of the micellar solution for the south pattern should begin midway through the next project year.

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RESEARCH SUPPORT
CHEMICAL SELECTION AND SUPPORT

by

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with

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Summary

Oil displacement tests using Shell and Union chemical formulations have continued in both Berea Sandstone cores and El Dorado 650-foot Admire Sandstone cores. Residual oil saturations in short (two-inch diameter by ten-inch long) El Dorado cores ranged from approximately 12 to 22 percent of the pore volume in flow tests using the chemical slugs designed by the process vendors. It was found that with the same surfactant slug size, residual oil saturation in Berea cores is approximately ten percent lower in four-foot cores as compared with ten-inch cores. An oil recovery test with a long stack of El Dorado cores (approximately 40 inches long) was in progress at the time this report was being written.

Total relative mobilities in Admire cores were measured during chemical flooding. They varied from 0.018 to 0.065 reciprocal centipoise. These values are in approximate agreement with those determined from relative permeability measurements.

Physical-chemical and transport properties of chemical slugs (micellar and polymer) have been investigated. A new type of chelating agent was selected to be used with the Union formulation. Methods of removing a type of undesirable inorganic salt in a petroleum sulfonate have been investigated. Several different polyacrylamide (synthetic) and polysaccharide (biopolymer) polymers were evaluated. It appears that the synthetic polymers manufactured by American Cyanamid and Nalco and the biopolymers produced by Kelco and Pfizer are the better candidates for use in El Dorado.

Major field work has included a field tracer test and work on water quality and injectivity improvement. The tracer test indicated that there was no gross channeling in the field. Water quality is improving but still not satisfactory. Preliminary results of a test in which Union preflush was injected into wells MP-225 and MP-211 did not show a decrease in injectivity. However, contrary to the injectivity test performed in well MP-104 in 1974, some difficulties have been experienced in the injection of soluble oil. —Investigation seeking to identify the cause of this low injectivity is in progress.

It is expected that the chemical selection and support activities will be heavily concentrated on field work during the chemical (micellar and polymer) injection periods for both processes.

Introduction

The primary functions of the work task referred to as "Chemical Selection and Support" are to evaluate the effectiveness of chemical formulations and design parameters, to make the selection of suitable (proper) chemicals for the various slugs, to assist in the handling and testing of chemicals in field operation, and to provide chemical support as needed throughout the entire life of the project. Since the micellar-polymer flooding process is such a complex and chemically oriented recovery method, chemical selection and support work plays a key role in this project.

During the early stages of the project, laboratory flow tests, chemical analyses, and the evaluation of fluid properties have been the major types of work performed. Handling, mixing, and testing of chemicals and chemical slugs in the field are expected to be the main effort throughout the chemical slug injection period. The analyses of produced fluids and samples from observation wells, demulsification, data documentation and interpretation, and process evaluation and appraisal will be the prime objectives at later stages of the project.

Discussion

Oil Displacement Tests

Shell Oil Company furnished preliminary design information for the El Dorado project to Cities Service in October, 1975. After several months of work on the design by both Shell and Cities, Shell submitted modifications to their design in March, 1976.

Oil displacement tests using the recommended Shell formulation in both Berea and El Dorado (Admire) short cores (two-inch diameter and approximately ten-inches long) were made. It was found that residual oil saturation

can be reduced to approximately one pore volume percent (one percent of the pore volume) in Berea cores. However, residual oil saturations in El Dorado cores have been considerably higher. Two tests with the original and revised slug designs showed that residual oil saturations in Admire cores were 12.2 and 21.7 percent, respectively.

Displacement tests with various sizes of the surfactant slug (for the Shell formulation) were also completed. It was found that residual oil saturation in Admire cores can be reduced to approximately five percent with a large slug size. Oil recovery versus surfactant slug sizes in both Berea and El Dorado cores are plotted in Figure A-1 of Appendix A.* A displacement test using the revised slug design in one-inch stacked cores about 40 inches long was in progress at the time this report was being prepared.

Oil displacement tests with the Union chemical formulation have continued. Residual oil saturations of 17.1 and 9.9 percent were obtained using the design slug size and using five times the design slug size, respectively. These tests were made in short cores.

Total Relative Mobility

Proper design for mobility control is extremely important in the chemical flooding process to maintain high oil recovery efficiency. Methods of determining the total relative mobility (λ_T) have been described by Gogarty, et al.^{1,‡} Steady- and unsteady-state relative permeability data using El Dorado cores were obtained. Determination of total relative mobilities from these data is discussed in greater detail in the section on "Coring and Core Analysis."

*All tables and figures are given in the Appendixes which form Part II of this report.

‡References for this section are given at the end of the section.

Direct measurement of the pressure drop across a small segment of stabilized oil-water bank during chemical flooding flow tests was also used to determine λ_T . Stacked cores approximately one inch in diameter by 20-inches long were used in these experiments. Results indicated that λ_T ranged from 0.018 to 0.065 reciprocal centipoise (cp^{-1}). These values are in approximate agreement with the minimum total relative mobility values obtained from most relative permeability measurements. Mobility data determined during chemical flooding are shown in Table A1.

Physical-Chemical Properties of Micellar Slugs

Micellar slugs are not only the most important but also the most complex fluids in the process. Their physical-chemical properties that relate to oil recovery efficiency, as well as injectivity, have been carefully investigated. Most of this work during this reporting period was concentrated on the Union soluble oil system due to the short lead time before injection.

The effect of salinity on phase behavior and viscometric properties of soluble oil mixtures for each batch of petroleum sulfonate received were determined. Quality control standards of the petroleum sulfonate supplier may not meet our requirements; this could cause problems in field operations. Recommendations for the resolution of difficulties with sulfonate include: (1) storing the required amounts of certain components in separate tanks; (2) testing the surfactants using representative samples of all surfactant components taken when sufficient amounts are available to blend in the design proportions and at that time making any minor formulation changes needed for the product to pass the performance tests; and (3) blending the components in only one or two batches so that any adjustments that may be necessary will be made on a minimum number of batches. Accumulated petroleum sulfonates are currently

undergoing testing at the laboratories of the sulfonate supplier, Union Oil Company and Cities Service. Final blending will be initiated as soon as results of performance tests from all three laboratories agree.

A new type of chelating agent for the Union formulation has been tested and found to perform satisfactorily. It is less expensive. A recommendation to use this type of chelating agent was made in January, 1976.

The effect of mixing between the soluble oil (Union micellar) bank and the polymer bank was investigated. Polymer solution of 900 ppm (parts per million) concentration was diluted with soluble oil and viscosities were determined as a function of soluble oil concentration. Viscosities of the polymer diluted with soluble oil were substantially below those of comparable dilutions with fresh water. Comparisons of soluble oil viscosity versus dilution and polymer concentration after addition of either water or soluble oil are given in Figure A-2.

The interfacial tension between the surfactant mixture recommended by Shell and El Dorado crude oil was measured with a spinning drop tensiometer. Values on the order of 10^{-2} dynes/cm were obtained.

There is an inorganic salt in one petroleum sulfonate that is incompatible with other chemical additives in the Shell formulation. Both gravitational and forced separation techniques have been investigated as methods to remove this undesirable material. A final recommendation for solving this problem has not yet been made.

Rheological Behavior of Polymers

Several types of biopolymers and polyacrylamides were screened for this project. Screening procedures included (1) rate of solubilization in filtered lake water, (2) rheological behavior, (3) filterability

through 0.45 micron millipore filter paper, (4) plugging tendency and mobility in cores, (5) adsorption by reservoir rocks, (6) interaction with surfactant solutions, and (7) chemical and shear degradation. Other factors such as economics, quality control by suppliers, and availability were also considered.

It was found that Pfizer polymer broth has the best performance among the biopolymers screened. However, due to the high cost of shipping, future economics are uncertain. From all the polyacrylamides screened, Nalco and American Cyanamid liquid polymers were found to be the most suitable in our system. However, consistency and quality control have been a major concern. The decision on the selection of a polyacrylamide polymer will be made in late summer of this year. The selection of biopolymer will be made late in 1976.

Transport Properties

Transport parameters such as cation-exchange capacity, dispersion coefficient, and adsorption on Admire rock were determined. Cation-exchange capacity was determined by continuous injection of a high concentration NaCl solution into El Dorado cores with measurement of the divalent ions in the effluent. Cation exchange capacity values of 0.044 and 0.071 milligram Ca^{++} per gram of rock were found for cores from wells MP-130 and MP-110, respectively.

Adsorption of the surfactants in the Shell chemical formulation on El Dorado 650-foot Sandstone cores was found to be in the range of 0.10 to 0.158 milliequivalents per 100 grams of rock. These adsorption data were obtained on extracted cores from well MP-215 under flowing conditions.

The dispersion coefficient in 650-foot Sandstone stacked cores from well MP-130 was measured and found to be on the order of 10^{-3} cm^2 per second. Generally, the dispersion coefficient in porous media at reservoir flow rates is a linear function of frontal velocity.² The data used here were measured at a frontal advance velocity of 15 ft/day.

Research effort in the determination of transport parameters and possible chromatographic type separation of a multicomponent surfactant system is in progress.

Field Work

A significant fraction of chemical selection and support time has been contributed to field work. This has included tracer, water quality, and injectivity tests.

Tracer test. Six chemical tracers were injected into the 18 injectors of both the Chesney and Hegberg patterns to detect possible gross channeling.

The total amount of tracers and the wells involved are summarized below.

<u>Tracer</u>	<u>Amount</u>	<u>Wells</u>
Ammonium thiocyanate	600 lbs	MP-126, 130, and 203
Formaldehyde	8 (55 gal) drums	MP-106, 110, 221, and 225
Sodium bromide	300 lb	MP-116, 120, 211, and 215
Ammonium nitrate	1500 lb	MP-128, 201, and 205
Potassium iodide	400 lb	MP-118 and MP-213
Sodium salicylate	600 lb	MP-108 and MP-223

During the early part of the test, samples of produced fluids were collected every six hours. After about ten days, the collection rate had been reduced to once a day. Samples were collected from the eight

production wells and the two observation wells. Locations of the observation wells are shown in Figure A-3.

Qualitative and quantitative analysis was carried out on each sample collected. The overall sampling period lasted approximately seven weeks. There was no breakthrough of any of the tracers.

Quality control of injection water. Good quality injection water is one of the most important factors in a chemical flooding process. It helps to ensure high injectivity throughout the entire life of the project. The injection water quality in the El Dorado field to date has not yet been consistently good due to reasons which include:

- a. Change of water source
- b. Unsatisfactory filtration
- c. Bacteria growth
- d. Interference (or incompatibility) of various treatment chemicals such as biocide and polymer flocculant.

A permanently mounted water quality testing device based on the principle of filterability was installed with lines to the fresh water tank, concentrated brine source, and injection water pumping stations (triplex pumps). One water quality test used measured flow rate through a 0.45 micron millipore filter at several different volumes of throughput. For good quality water, millipore data indicate an initial flow rate of about 10 ml/sec with a flow rate still above 4 ml/sec after three liters have passed through the filter. (However, allowances must be made for viscosities not close to one centipoise.) A discussion of a method for determining water quality criteria has been given by Barkman and Davidson.³ Water quality was tested at least once a day depending on the consistency of water quality. Considerable effort has been and still is being made to improve the water quality (see also the section "Pattern Injection and Production).

Injectivity test. Due to the experience of poor injectivity at the initiation of the salinity adjustment slug, a series of injectivity and chemical sensitivity tests were performed in the laboratory with cores from wells MP-215 and MP-106. The results indicated that (1) these cores are not sensitive to fresh water, (2) the Union chemical preflush caused a reduction of permeability, and (3) pretreatment with the Union soluble oil would improve the injectivity of chemical preflush. Based on these data and the injectivity test performed in well MP-104 in 1974, soluble oil pretreatment tests were initiated in May in wells MP-225 and MP-211. Additional discussion of this topic, including results of the laboratory core tests mentioned here, is given in the section "Formation Injectivity Tests."

Miscellaneous Chemical Work

Recommendation for the drilling of observation wells, field laboratory set-up, analytical work, and scale prevention are discussed in this section. A related study of the effect of heating on wettability of native-state El Dorado cores is reported in the section on "Coring and Core Analyses."

Observation wells. Recommendations for drilling of observation wells were made by one process vendor and Cities Service Laboratory personnel. Two observation wells were drilled in each pattern in the spring of 1976. The locations of the observation wells are shown in Figure A-3.

These wells are being used for daily sampling of fluids and are logged less frequently. Samples from observation wells have been taken and analyzed since April. Breakthrough of the salinity adjustment slug has occurred at observation well MP-131. Figure A-4 shows the change of

salinity versus time for this well. There was no change in salinity in well MP-227 up to the end of May.

Detailed information on the drilling and completion of these wells is given in the section "Observation Wells."

Field laboratory set-up. A laboratory was set up at the plant site to perform simple testing and analytical work related to field operations. Major equipment in the laboratory include: a Brookfield viscometer, an automatic titrator, a high speed centrifuge, an analytical balance, and filtration test apparatus. Routine analytical work such as chloride, hardness, alkalinity, biocide, and oxygen scavenger content determinations and water quality tests are carried out at the field laboratory. Other types of work, such as soluble oil performance tests and rheological properties of chemical slugs, can also be performed at the plant site.

Chemical analyses. Chemical analyses have been a major portion of the supporting work for this project. Specific areas of analytical work have been concerned with petroleum sulfonates (ASTM 2548-69 and a two phase, two dye titration⁴), polymer (colorimetric method⁵), and more common analyses of produced waters and solid particles in injection waters.

Due to the presence of sulfate ion in wells MP-114 and MP-207, produced waters from 44 wells in the field were analyzed in an effort to determine its source. The results were not conclusive. Analytical results for produced water from wells MP-114 and MP-207 are given in Table A2.

Scale prevention. Due to the presence of barium and sulfate ions in the field (not from the same wells), the original plan of using

produced water from MP-207 to adjust injection water salinity was changed. However, scale samples from wells MP-114 and MP-207 and the heater treater at the plant were positively identified as barium sulfate. Recommendations for BaSO_4 scale prevention with Visco 953 (a product from Nalco) and treatment of CaSO_4 scale with sodium-EDTA were made. The sodium-EDTA treatment was found to be only temporarily effective. Visco 953 has prevented scale formation, but has a high, undesirable feed-back rate. A total of 17 scale inhibitors were tested in the El Dorado mixed, produced water system. It was found that Visco 953 and a controlled solubility phosphate (solid) scale inhibitor, SP-171 (by Tretolite), were more efficient in scale prevention. Tretolite SP-171 is being used in producing wells for barium sulfate scale inhibition.

Literature Work

The literature survey on chemical flooding and alkaline water-flooding was updated and a number of additional references were found. A rough draft of a report covering this survey has been completed. A preliminary copy of the bibliography for this report was furnished to the United States Energy Research and Development Administration. This report will be published within a few months.

Future Work

Oil displacement tests with both Union and Shell chemical formulations in El Dorado native-state cores will be continued. These tests are scheduled for the purposes of scale-up, optimization, and polymer selection.

Mobility determination is expected to be completed in the near future.

Additional soluble oil injectivity and Shell chemical slug injectivity tests are scheduled for this summer. The selection of a suitable polymer for the Hegberg lease should be made in the late summer of 1976. The polymer selection for the Chesney pattern is to be made late in 1976.

Intensive chemical analyses of samples from observation wells and documentation and interpretation of the results should begin shortly after the injection of chemical preflush.

The demulsification program will be re-initiated if an oil-emulsion bank reaches the observation wells.

Handling, mixing, and testing of chemicals for both patterns will be the major fraction of field-oriented work after the initiation of chemical slug injection.

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CORING AND CORE ANALYSES

by

W. H. Pusch

with

W. R. Almon, G. A. Flesch, and G. E. Kellerhals

Summary

During the past year, four observation wells have been cored. These cores have been preserved with no routine core analysis performed. Special core tests to measure rock wettability and fluid mobilities, in addition to several routine core analyses, have been performed. Geological interpretation of the environmental setting of the formation has continued along with analysis of reservoir permeability characteristics.

Introduction

To understand the performance of the micellar-polymer process, an accurate description of the entire reservoir is necessary. Analyses of project cores to determine reservoir properties is continuing, and the data are now being applied to develop a model for simulation. Although geological information has defined two distinct zones with limited vertical communication, permeability analyses have shown that the two layers have nearly the same average absolute permeability. Relative permeability data are still being measured on native-state core samples using produced El Dorado oil and water. Total fluid mobilities calculated from the relative permeability data will aid in evaluating the micellar-polymer process.

Discussion

Core Analyses

A total of 25 cores from the project area have now been analyzed. Routine core analyses were performed on cores from wells MP-112, 114, 126, 128, 207, and 211 during this reporting period. Results are given in Tables B1 through B6 in Appendix B. Core from well MP-128 was analyzed at the Shell Laboratory in Houston. MP-114 and MP-207 cores were analyzed to determine porosity, permeability, and oil saturation using the procedure of sampling at one-foot intervals along the core. Samples were cut from MP-207 for core flow tests prior to analysis, and a significantly lower oil saturation can be seen in the results for this core (Table B5). The two reasons the oil saturations were not as high as those measured in other project cores would seem to be that most of the good sand was removed for plugs to be used in flow tests and that the core was allowed to dry by exposing it to the atmosphere.

Oriented cores were taken from wells MP-112, 126, and 211. The permeabilities of these cores were measured with whole-core techniques. Whole-core air permeabilities were measured along both the north-south and east-west axes to determine if any directional trends could be detected. The average ratios of north-south permeabilities to east-west permeabilities were 1.06 for MP-126, 1.07 for MP-112, and 1.08 for MP-211. It appeared that although the north-south direction had consistently higher values, the difference was not significant within an individual core. Plug measurements taken from the same intervals as those determined by the whole-core technique gave results higher than those reported by whole-core analysis. This suggests that geometric averaging of plug data results might produce lower averages, that is, averages closer to the values obtained by whole core methods.

Coring

Four observation wells were drilled and cored during the last year. Wells MP-131 and MP-132 were drilled southwest of the center injection well for the Chesney pattern, well MP-118. Well MP-131 is 90 feet from MP-118, and well MP-132 is half-way between injection well MP-118 and production well MP-124 (see Figure A-3 in Appendix A or Figure G-39 in Appendix G).

MP-227 and MP-228, the Hegberg observation wells, are located southwest of the center injection wells, MP-213 and MP-226. Their spacing between injection well MP-213 and production well MP-219 corresponds to that between the Chesney observation wells and wells MP-118 and MP-124. The cores from these wells are to be used for flow tests rather than routine core analyses.

Additional data concerning the locations, depths, coring, and completion of the observation wells is given in the section "Observation Wells."

Permeability Distribution

An important objective of the demonstration project is to obtain data that will allow accurate evaluation of the process and provide a sound basis for design of a field-wide expansion. An attempt to model the movement of oil and chemicals through the formation requires a detailed knowledge of the permeability of the reservoir rock. Geologists have examined the cores and have provided an explanation of the environment of deposition for the project area. They subdivided the sandstone into two portions: the upper sandstone being a channel deposition and the lower zone consisting of shaly siltstones interlayered with medium-grained to very fine-grained sandstones characteristic of an intertidal environment. Results of the permeability studies reflect the two general subdivisions. The permeability of the lower zone appears more heterogeneous. However, the average permeability values of the two zones are nearly equal. Occurrence of low permeability shaly siltstone layering restricts communication between the upper and lower zones and also isolates high permeability sands within the lower zone.

Several mathematical models have been proposed to describe fluid mobility based on geological features and laboratory data, but none has proved entirely satisfactory. Application of a Dykstra-Parsons analysis to core permeability data has yielded somewhat inconclusive results. When all data points are plotted (logarithm of permeability versus fraction of data points having greater permeability) two line segments result as shown in Figure B-1. Attempts to match points in each line segment to their location within the reservoir has shown no direct correlation. The right-hand side (low permeability portion) of the plot in Figure B-1 represents data from shaly zones, primarily in the lower subdivision. However, most of the highest permeability data were also measured on samples from the lower zone.

As lower permeability samples are eliminated from the Dykstra-Parsons analysis, a straight line is approached. However, the cut-off value is nearly 100 millidarcies; this high cut-off value would seem to omit portions of the reservoir through which fluids would flow. The average (log) permeability increases considerably if 100 millidarcies is taken as the lower limit. Table B7 presents data using several averaging techniques and the Dykstra-Parsons variance coefficient. Notice that the arithmetic and logarithmic (geometric) average tend to converge as the lower limit of permeabilities considered is raised to ten and then to 100 millidarcies.

If the number of samples falling in various ranges for normal or arithmetic distribution are plotted as in Figure B-2, it becomes obvious that the permeability data fits a normal distribution better than a log-normal distribution. A log-normal population results if the low permeability samples are not included.

Therefore, if the data are to fit a normal-type distribution, this data analysis shows that an arithmetic average should be used. If a logarithmic average is to be used, this analysis indicates that low permeability data should not be included. The section on "Performance Prediction" also includes a discussion of this topic. The primary point made there is that for mathematical modeling, the data do not need to fit either a normal or log-normal distribution; the actual data can be used as determined.

Wettability

Two studies were performed by ERDA (the U. S. Energy Research and Development Administration) on native-state core plugs from several project wells. The first study measured wettability of samples from wells MP-114, 124, 209, and 217 to determine how wettability varies over the project area. The second study attempted to determine if paraffin or wax deposition in the core plugs can alter rock wettability.

ERDA measures wettability by the method described in a paper by Donaldson, Thomas, and Lorenz.¹ A total of eight samples were tested from two Chesney and two Hegberg cores. Results shown in Table B8 indicate the plugs from the Chesney pattern were slightly more negative on the scale used. A strongly oil-wet core would have a value of -1; a strongly water-wet core would be +1; and a core of intermediate wettability would have a value of zero.

Four samples from well MP-114 were tested to determine if heating the core plugs which contained formation brine and formation crude oil (at residual saturation) would noticeably alter rock wettability. Heating should cause wax which might be present to redissolve into the crude oil. Core plugs were 3/4-inch diameter by 2 1/2-inches long. The plugs were cut into a "top" and "bottom" portion. All of the plugs were saturated with El Dorado brine. However, the beaker which contained Chesney brine and the "top" portion of core plugs was placed in an oven at 125° F and left overnight. The results shown in Table B9 indicate that all of the cores were somewhat oil wet, and cores which had been heated were less oil wet. It has been suggested that the oil-wet tendencies resulted from core aging.¹ Well MP-114 was cored in March, 1975, and laboratory wettability measurements were performed one year later. However, the core was wrapped and sealed in wax at the well site within about one hour from the time it reached the surface.

Relative Permeability

Steady-state relative permeability studies were performed on core samples from wells MP-124 and MP-217. The results are shown in Table

¹Donaldson, E. C., R. D. Thomas, and P. B. Lorenz, "Wettability Determination and Its Effect on Recovery Efficiency," Society of Petroleum Engineers Journal, 9: 13-20, March, 1969.

B10. Native-state conditions were maintained by eliminating contact of the samples with air and using only El Dorado crude oil and formation water in sample preparation and in the flow tests. Mobility data from these studies will be used in conjunction with the measurements of total mobility and total relative mobility in designing the micellar-polymer process. These other mobility measurements are discussed in the section on "Chemical Selection and Support."

Two-inch diameter flow samples were drilled from the wrapped cores and underwent the following procedure. El Dorado crude was injected through the sample displacing all mobile water. An oil permeability was measured at this condition (the initial point in Table B10), and the sample was weighed to determine the fluid saturations. El Dorado formation water was injected simultaneously with crude oil at increasing water/oil ratios. Permeability and saturation data were measured after each of the flow rates and pressure had stabilized. The sequence of flow ratios selected were 100 percent oil, 10 oil/1 water, 1 oil/1 water, 10 water/1 oil and 100 percent water. The final point simulates floodout conditions with the water permeability and residual oil reported in Table B10.

The test cycle was then reversed with the flow ratios of water to oil decreasing. Points at which data were measured included 100 percent water, 10 water/1 oil, 1 water/1 oil, 10 oil/1 water and 100 percent oil. The test plug was then extracted with toluene, with the amounts of oil and water removed determining the final saturations in the plug. At this time the pore volume of the sample was calculated allowing the determination of intermediate saturations from the weights measured. The air permeability of the cleaned, dry plug was then determined; the relative permeabilities were based on this value. The relative permeabilities and the corresponding

saturations were plotted and the curves drawn, see Figures B-3 through B-8. Note, Figures B-7 and B-8 present results for the same core; Figure B-8 shows results of a test made after the core was extracted. Total fluid mobilities calculated from relative permeability data are given in Figures B-9 and B-10.

A series of tests were performed on El Dorado core samples to determine end-point saturations obtained during water imbibition and drainage floods. Test samples were drilled from the MP-124 core using El Dorado water as a drilling fluid. The testing procedure included flowing oil through the sample until no water production was obtained. At this point an oil permeability was measured. Water was then flushed through the sample until no additional oil was removed. A water permeability was determined at the residual oil saturation. Fluid saturations were calculated using a Dean-Stark extraction following the testing of each sample. The weight lost during the toluene extraction process represented the amount of oil and water in the sample. Water was condensed, trapped, and measured, while oil was calculated by weight difference. In addition, two samples were cleaned before testing to evaluate the effect of native-state coring.

Three different oils were used in the study: Soltrol 130 (1.4 cp), Carnation oil (18 cp), and Chesney crude oil (8.5 cp). The results are given in Table B11. Residual oil saturations for Soltrol averaged 16 percent, for Carnation oil 21 percent, and for Chesney crude oil 24-29 percent. The extracted cores produced final oil saturations of 26-28 percent.

Most of the coring and core analyses work described above was also presented at a Society of Petroleum Engineers meeting last spring.²

²Pusch, W. H., "Core Analysis Study for the El Dorado Micellar-Polymer Project," Society of Petroleum Engineers of AIME, Improved Oil Recovery Symposium, Paper No. 5806, March 22-24, 1976.

Geology^{*}

A detailed geological study was performed to recognize rock parameters controlling porosity and permeability, to define favorable reservoir facies trends, and to allow possible prediction of the oil recovery for the Admire Sandstone. Data from geological analysis of 23 cores have been synthesized, yielding a deltaic depositional model of the reservoir sandstone. The model outlines favorable facies trends which are based on the types of sandstone present in the reservoir. Analysis of three oriented cores (MP-112, 126, and 211) allowed determination of distributary channel paleocurrent directions which indicate preferred permeability trends. The paleocurrent stream transport directions were based upon measurements of trough cross-bed axes from the reservoir sandstone.

The environmental setting for the project area is deltaic and can be further divided into distributary channel, intertidal, and splay channel subenvironments. Directional findings obtained from the oriented cores indicate the distributary channels have two major flow directions: from south to north along the western area and east to northeast in the area between the two patterns (this is illustrated in Figure B-12, discussed later).

A detailed geologic column (Figure B-11) indicating the rock character of core from well MP-213 illustrates the inter-relationship of distributary channel, interbedded splay channel, and intertidal sandstones in the Admire 650-foot Sandstone. The overall thickness of the reservoir

^{*} Barbara Keltner also contributed much to the understanding of the geology of the Admire 650-foot sandstone as a temporary employee at the Cities Service Exploration and Production Research Laboratory. The primary report on her work is to be her Master's Thesis, completed as a part of her graduate work at the University of South Carolina.

sand is thinner in the region of well MP-213 than normally encountered in the project area. The sandstone gross thickness and thicknesses of the environmental subunits have been interpreted from core descriptions of 23 wells as shown in Table B12. Areas of high percentages of distributary channel reservoir are apparent in the west and northeast parts of the project area.

Horizontal and vertical permeabilities between wells are greatest for the distributary channel sandstones. Splay channel sands are interbedded with intertidal deposits, and although of high permeability, they have limited lateral distribution. Their contribution to the net reservoir sand thickness is moderate. Intertidal deposits contain interlaminated shale and sandstone with extremely low permeabilities; these may act as local flow barriers.

Intermixing of distributary channel deposits with splay channel and intertidal deposits for the sand in the project area is shown in Figure B-12. The distributary channel facies are probably continuous across the area although the thickness does vary. Splay and intertidal deposits are commonly intermixed and are designated as "mixed zones." In the mixed zones distributary channel sands form less than 70 percent of the reservoir. The most favorable reservoir facies are those interpreted to be greater than 70 percent distributary channel sandstone. The geological analysis indicates that the southeast area of the Hegberg lease is an area which should be difficult to flood while the western portions should have high permeability characteristics.

Clay mineral analyses were performed on core samples from six wells which were experiencing loss in fluid injectivity. Results of X-ray diffraction analysis indicated that the clay minerals present should not

cause any excessive loss in formation flow capacity. In addition, no definite relationship or correlation could be determined between the clay content of the six wells and their injectivity behavior. Table B13 presents the results of the mineralogical analyses.

Future Work

In the next year samples of cores will be used frequently for flow tests studying rock-fluid interaction and oil recovery.

WELL LOGGING

by

H. M. Al-Rikabi

Summary

As reported earlier in the section on coring and later in the section on drilling the wells, four observation wells were drilled during the last year. The observation wells are being logged to provide early data for evaluation of the effectiveness of the micellar-polymer processes and information needed to improve the processes. The accurate determination of residual oil saturation is very important for the field evaluation of micellar-polymer processes. Both open-hole and cased-hole well logging programs were used. The open-hole type Epilogs run after fiberglass casing was cemented were found to be a direct over-lay of the initial open-hole Epilogs run for the same wells before the fiberglass casing was set.

Introduction

The accurate determination of residual oil saturation is very important for the field evaluation of a micellar-polymer flooding process. Accurate residual oil saturation is needed to determine the displacement efficiency and vertical sweep efficiency. Logging observation wells is a good method of providing early data to evaluate the effectiveness of a micellar-polymer process and to provide information needed to improve the process.

Well logging has been one of several formation evaluation techniques used for the determination of oil saturation. Both open-hole and cased-hole well logging programs have been available for the analysis of formation data. Formation water was used for drilling so that the mud filtrate and formation water would be of equal salinity. The primary logging tools used in the field were:

1. Dual Induction-Laterolog, Focused Log (DIL-LL-FL)
2. Compensated Densilog and Neutron Log
3. Carbon Oxygen-Neutron Lifetime Log
4. Gamma Ray and Caliper Log

Discussion

Figures C-1 and C-2 are the base logs for well MP-228 and serve as an example of the logs obtained. From these logs, the Epilog^{*} analysis was developed. The Epilog, a log analysis of hydrocarbon bearing formations by computer, provides a quick and complete look at the interval of interest. The Epilog system converts well logging measurements to formation parameters

* Copyright, Dresser Atlas

which can be rapidly evaluated. Figures C-3 to C-6 are the Epilog presentation of the computed results from open-hole logging of individual observation wells. (See the section "Observation Wells" for details concerning the drilling and completion of the four observation wells.) Figures C-7 to C-9 are the Epilog presentations of the computed results from cased-hole logging for individual wells. The cased-hole Epilogs are a direct over-lay of the open-hole Epilogs.

Tables C1, C2, and C3 show the results of the open-hole logging evaluation for the four observation wells, MP-131, 132, 227, and 228. The tables summarize gross pay, net pay, pore volume, porosity, hydrocarbon pore volume, residual oil, oil in place, movable oil, permeability index, clay percent, and their arithmetic, weighted averages, and geometric mean. The average oil saturation determined by logging the observation wells was less than the average oil saturation determined from the other wells on the leases. Since injection into the nearest injection wells commenced several months before the observation wells were drilled, observation well saturations may have been somewhat influenced by the injected fluids. Tables C4 to C7 show the computed results of the evaluation of the open-hole logs for the individual wells. Table C8 shows the geometric and arithmetic averages for the observation wells.

Future Work

Logging of the observation wells will be used intermittently for monitoring sweep efficiency and field evaluation of the micellar-polymer processes.

FORMATION INJECTIVITY TESTS

by

S. C. Swift

with

H. L. Chang, V. W. Rhoades, E. F. Riedel, and G. W. Rosenwald

Summary

Injectivity testing on well MP-104 during 1974, indicated an injectivity to Union's chemical preflush of 0.2-0.3 bbl/day/psi while drive water averaged 0.5 bbl/day/psi. Preflush injection subsequent to injecting the complete sequence of Union chemical formulations was approximately 0.5 bbl/day/psi. Although the physical or chemical reasons for this improved preflush injectivity during the second sequence are uncertain, the most reasonable explanation was that the soluble oil served to clean up the immediate wellbore area and helped stabilize any clay problems. Laboratory flow tests also indicated pretreatment of cores with soluble oil could be used to avoid injectivity reduction when injecting chemical preflush. Therefore, a field test to determine whether a soluble oil slug preceeding the preflush would reduce any loss of injectivity to preflush was undertaken in May of 1976.

Injectivity of the various fluids in the Shell process will be field tested in well MP-101. This test is expected to commence in the first part of August, 1976.

Introduction

The prime objective of injectivity testing is to determine in advance the expected response of the project wells to the injection of various fluids. Extensive injectivity testing of the materials involved in the Union process were reported in the first annual report.¹ The most serious problem encountered was the low preflush injectivity which was often below 0.2 bbl/day/psi and averaged only 0.3 bbl/day/psi. Subsequent to injection of the entire sequence of chemicals in the Union formulation, injectivity to preflush was much better (approximately 0.5 bbl/day/psi).

The physical or chemical reason for this behavior was uncertain. Several possibilities were postulated. In order to study the nature of the injectivity reduction, two laboratory tests were conducted. Well MP-225 was then selected to test these results in the field. Well MP-211 was selected to serve as a control sample, in that no soluble oil pretreatment would be used ahead of the chemical preflush injection in this well.

Discussion

In the injectivity test reported in the first annual report the injectivity of the chemical preflush was much better when injected after the entire sequence of chemicals in the Union formulation. Although the physical or chemical reason for this behavior was uncertain, possible explanations were hypothesized. The most reasonable possibility was that the soluble oil had served to clean up the reservoir rock in the vicinity of the wellbore and/or to stabilize clays in the reservoir materials at

¹Rosenwald, G. W. and R. J. Miller (editors), El Dorado Micellar-Polymer Demonstration Project (First Annual Report). Oak Ridge, Tennessee: United States Energy Research and Development Administration, Report No. BERC/TPR-75/1, October, 1975.

the sandface. Laboratory flow tests were performed to test this hypothesis. These tests, which were also discussed in the section on "Chemical Selection and Support," could also be called chemical sensitivity tests. Table D1 lists the results of two flow experiments conducted to test the effect of using a soluble oil pretreatment. These results indicated that (1) these cores are not sensitive to fresh water, (2) the Union chemical preflush caused a reduction of permeability, and (3) pretreatment with the Union soluble oil would improve the injectivity of chemical preflush.

Based on the data from these tests and the injectivity test performed on well MP-104 in 1974, soluble oil pretreatment field tests using wells MP-225 and MP-211 commenced on May 12, 1976. These tests should be completed in June. As of the writing of this report, no additional data on the effect of soluble oil pretreatment on preflush injectivity is available.

A third laboratory test used a single plug mounted in epoxy with pressure ports sealed into the plug a short distance from each end. This test was primarily designed to compare the injectivity of various aqueous fluids. Therefore, soluble oil treatment was not used. The results, as shown in Figure D-1 (where injectivity is expressed as k/μ rather than $Q/\Delta p$), indicated that the core is not sensitive to fresh water. Moreover, the data also indicated that there is only a little variation in injectivity across the control section (pressure taps) for the various fluids.

Future Work

Field testing of the soluble oil pretreatment idea for improving preflush injectivity will be completed in June, 1976. The major injectivity test during the coming year will be on the chemicals involved in the Shell

process. This complete sequence will be injected into well MP-101 (a test well outside the pilot area) to measure actual injectivities obtained and to determine operating problems involved in handling, mixing, and injecting the various fluids. This test is scheduled to commence in the first part of August, 1976.

PATTERN PRESSURE TRANSIENT TESTS

by

S. C. Swift

with

L. P. Brown and V. W. Rhoades

Summary

All eight producing wells in the project were pumped in order to determine the condition of the wells themselves and also to obtain drawdown at the offset injectors as a result of interference from the central producing well. This interference data served as the basis for selecting the pattern orientation that would minimize early breakthrough of the injected fluid. The orientation selected was a 6.4 acre five-spot pattern with injectors on north-south and east-west lines. Study of the accumulated data resulted in a major technological advancement of the analytical techniques for evaluating interference tests.

The 18 wells selected for injection were subjected to brief periods of gravity injection of filtered Chesney brine. The subsequent fall-off data served to define the initial condition of each of these wells. As a result of the fall-off tests, the buildup tests, and other considerations, several of the wells were subjected to various stimulation techniques in an attempt to increase the injection rates. These treatments are described in the section "Pattern Injection and Production." Pressure fall-off test results before and after clean out are included here for five of the injection wells.

Introduction

Two types of pressure transient tests were conducted during the second project year. The first type of test involved producing each production well, shutting in for a pressure buildup test, and monitoring offset injection wells for interference during the production and shut-in periods. This type of test is referred to as a Production/Buildup/Interference Test.

The second type of test was performed on injection wells. After water had been injected into an injection well for a short period of time, the well was shut in and pressure falloff was monitored. Interference data at offset locations were not recorded during these tests. This type of test is called an Injectivity/Fall-off Test.

Discussion

Production/Buildup/Interference Tests

These tests were performed on each quadrant of the El Dorado Micellar-Polymer Project. Here a "quadrant" is used to mean a producing well with surrounding injection wells. Each test was set up and conducted in essentially the same manner. A description of a typical test is given below.

A surface recording bottom-hole pressure gauge was run down the tubing/casing annulus of the production well. An electrical fluid level indicating device was run in each of the eight offset injection wells.

The pump was started on the production well, and fluid was produced until two days had elapsed or 200 barrels of fluid were produced (which ever was last). At this point the production well was shut in and buildup data were recorded. Simultaneously, during the production and

buildup periods, fluid levels in the eight offset injection wells were recorded. The fluid levels provided interference data at the offset locations.

The pressure buildup at the production well was analyzed in the conventional manner for formation permeability and wellbore damage (skin factor). The interference data at the offset locations were analyzed for directional permeability using a technique developed during the project.

The analysis technique, theory, and application were described in a report entitled "Directional Permeability Analysis; El Dorado Micellar-Polymer Project" and submitted to ERDA (the U. S. Energy Research and Development Administration) as a special project report. The report described the tests, results, and analysis of the complete interference test program. The analysis of this test provided the basis for choosing between a 6.4 acre and a 3.2 acre spacing plan.

The special report was also presented as a paper at a Society of Petroleum Engineers Symposium.¹ The analytical method, results, and important conclusions are described briefly here. Additional and specific details can be found in the special report or the paper.

One technique of interference analysis involves the use of "type curve matching" or determining how field data can be fitted to standard "type curves" (curves of dimensionless pressure versus dimensionless time.) Once a unique "fit" is determined, reservoir properties can be calculated. Dimensionless pressure is expressed as

$$P_D = \frac{kh(P - P_i)}{141.2 q\mu B} \equiv \frac{\Delta P}{\Delta P_1}$$

¹Swift, S. C. and L. P. Brown, "Testing for Reservoir Definition--The State of the Art," Society of Petroleum Engineers of AIME, Improved Oil Recovery Symposium, Paper No. 5809, March 22-24, 1976.

where k = formation permeability, md

h = net pay, feet

q = flow rate, bbl/day

μ = viscosity, cp

B = formation volume factor, $\frac{\text{reservoir bbl}}{\text{stock tank bbl}}$

P_i = initial pressure, psi

P = pressure at any time, psi

$$\Delta P = P - P_i, \text{ psi}$$

$$\Delta P_1 = \frac{141.2 q \mu B}{kh}, \text{ psi}$$

Dimensionless time is expressed as

$$t_D = \frac{0.000264 kt}{\phi \mu c_t r^2} = \frac{t}{\Delta t_1}$$

where t = time since start of test, hours

ϕ = porosity, fraction

c_t = total compressibility, psi^{-1}

r = distance between wells, feet

$$\Delta t_1 = \frac{\phi \mu c_t r^2}{0.000264 k}, \text{ hours}$$

Once a fit of field data to theoretical curves is obtained, the dimensionless pressure equation can be solved for k , the formation permeability. If the product $\phi \mu c_t$ is known, the dimensionless time term can also be solved for permeability.

In the special report to ERDA, it was shown that the k obtained by solving the dimensionless pressure equation is the geometric average permeability around the well, whereas the permeability found by solving the dimensionless time equation is the permeability between the pulsing and respondi

wells, or simply directional permeability. For this reason, the dimensionless time equation is rewritten as

$$t_D = \frac{0.000264 k_\phi t}{\phi \mu c_t r^2}$$

where k_ϕ = directional permeability, md.

The permeability term in the dimensionless pressure equation is written as k_e to emphasize that this is the effective permeability around the wellbore. Thus, one has

$$P_D = \frac{k_e h (P - P_i)}{141.2 q \mu B}$$

The results of the interference tests are summarized in Tables E1 and E2. Data were not available to determine directional permeability between wells MP-112 and MP-110 because well MP-110 was not in communication with the formation during these tests. The packer shoe had failed during the cementing operation in MP-110 which left a cement sheath around the wellbore that was later removed.

The directional permeability data were reviewed to determine which of two possible orientations of the flood pattern would result in more uniform sweep. Another parameter, permeability contrast, δ , was introduced. This parameter is the ratio of the highest to the lowest directional permeability in each quadrant. Obviously, values of δ close to 1.0 imply a more uniform sweep than do high values of δ .

Figures E-1 and E-2 show the two possible flood configurations and summarize the directional permeabilities and permeability contrasts for each orientation. Clearly, the 6.4 acre spacing is preferable to the 3.2 acre spacing.

Important conclusions made during this study were:

1. The 650-foot Admire Sandstone reservoir appears to be randomly heterogeneous.
2. The 6.4 acre five-spot pattern with its associated orientation will result in a more uniform sweep than the 3.2 acre five-spot pattern.
3. The techniques developed for analysis of El Dorado data can be used to predict directional properties of a reservoir from interference test data.
4. Conventional analytical techniques used to predict directional tendencies can lead to conclusions which are completely erroneous.

Results of the pressure buildup tests on the production wells are summarized in Table E3. These analyses were done in a conventional manner. Well MP-114 was not analyzable because of restricted flow rate apparently caused by a large positive skin. (See the section "Pattern Injection and Production" for more information about well MP-114.)

Injectivity/Fall-off Tests

Testing of each of the injection wells to be used in the project was necessary in order to establish their injectivity and damage factors prior to starting the project. Filtered brine from Chesney well 195 was allowed to gravity feed into each of the wells for eight hours. The wells were then shut in and pressure recorded using Amerada surface recording bottom-hole pressure gauges. These tests were analyzed using standard fall-off analysis techniques (Horner semi-log method). The results are shown in Table E4.

As a result of these tests and other observations, several wells were cleaned out to the desired depth while others required perforating the bottom section of casing followed by an acid cleanup. The results of these jobs were determined by retesting each well (as described above) following the work. Results of these tests are tabulated in Table E5.

Future Work

Pressure transient tests will be conducted on active production and injection wells throughout the life of the project. These tests will be scheduled as required to determine well conditions during injection of the various chemical solutions. In addition periodic checks on the bottom-hole pressure in each of the monitoring wells will be made to determine the amount of pressure buildup in the vicinity of the project.

PERFORMANCE PREDICTION

by

J. Vairogs

with

C. M. Royo, D. A. Siebert, and D. F. Zetik

Summary

Development and improvement of chemical flood performance prediction methods has continued. Improvements were made in the superposition-of-line-sources program, streamline program, and oil recovery program. The documented listing for the streamline program was given to ERDA earlier this year. Programs are being developed to include reservoir heterogeneity in recovery calculations and to provide a rational slug size calculation procedure for any pilot or full-scale operation.

The existing programs were used to predict the performance of individual wells and the demonstration flood. The four salient applications were to:

1. Show that a constant bottom-hole injection well pressure of 400 psia and a constant bottom-hole producing well pressure of 30 psia will substantially increase well rates and result in acceptable project life for the eight, 6.4-acre five-spot patterns.

2. Use the above calculated rates to set relative rates for wells so that each well would get the proper fraction of injection fluid.
3. Estimate the effect of explosive fracturing and twinning on the rates of wells MP-118 and MP-213. Results showed that both twinning and explosive fracturing were required to raise the rate of well MP-213 to the desired level.
4. Show that in this demonstration flood, operating at constant wellhead injection pressure was more desirable than operating at a high injection-to-production rate ratio. Extensive calculations were made to compare the performance of the demonstration flood operated under various well rate and bottom-hole pressure conditions against the performance of a confined five-spot.

Introduction

This section describes performance forecasting and monitoring and the associated program development work. Reservoir heterogeneity is examined in detail. Well injectivity improvement, well operating conditions, oil recovery, chemical slug size, and polymer slug calculations are described. Monitoring of well performance and development of a production data base are also included. A description of program development to handle anisotropic permeability and reservoir heterogeneity is included.

Discussion

Forecasting

Reservoir heterogeneity. Revised values of reservoir pore volume and oil presently in place were computed for the project area. These new values are based on the analysis of well logging data presented in Table C5 and Table C11 of the First Annual Report for the El Dorado Project.^{1,*} The product of net thickness and the geometric-mean porosity was computed for each well. A contour map was prepared from these porosity-thickness data. This contour map was then integrated to obtain the total pore volume enclosed within the boundaries of the Chesney and the Hegberg patterns. Next, the product of net thickness, geometric-mean porosity, and geometric-mean oil saturation was computed for each well. A second contour map was prepared from these results. This second map was integrated to obtain the volumes of oil that are now present within the confines of the two patterns. By dividing the volume of oil within a pattern by the total pore volume of the pattern, average oil saturation was obtained for each of the two patterns.

*References for this section are listed at the end of the section.

The revised reservoir pore volume, oil presently in place, and average present oil saturation are presented in Table F1. Some of the values in this table are slightly different from the values presented in the First Annual Report. Although the basic data used to get the present values are the same that were used to get the values in the First Annual Report, the contour map integration technique is mathematically more sound than the technique that was previously employed. Thus, the revised values will be used in all calculations.

The core and log analysis data from Tables B1 through B19 and C12 through C65 of the First Annual Report were used to study aerial and vertical variations in reservoir properties. Core photographs and well logs were employed to separate data for each well into an upper and a lower zone. The average permeability for each zone in a well was obtained by geometrically averaging the core permeability data. Samples with permeability less than 0.05 millidarcy were not included in the average. The mean porosity and mean oil saturation for a zone were obtained by arithmetically averaging the log analysis data. The zone thicknesses, average permeabilities, average porosities, and average oil saturations for the wells that were studied are presented in Table F2.

Thickness-weighted, arithmetic average zone porosity and permeability together with arithmetic average zone thickness for Chesney and Hegberg patterns are presented in Table F3. The thickness-weighted average zone porosity for a pattern was obtained by dividing the sum of the porosity-zone thickness products for the individual wells by the sum of the individual well zone thicknesses. The thickness-weighted zone permeability for a pattern was obtained by dividing the sum of the permeability-zone thickness product for individual wells by the sum of

the individual well zone thicknesses. Table F3 also contains average zone properties for the combined patterns making up the project.

The average thickness of the upper zone is greater than the average thickness of the lower zone. There is little difference between a zone thickness in one lease (pattern) and its thickness in the other lease. The average porosity of the upper zone is almost identical to the average porosity of the lower zone. The zone porosities in the Chesney lease are almost identical to the zone porosities in the Hegberg lease. In the Chesney lease, the lower zone is slightly more permeable than the upper zone. In the Hegberg lease, the upper zone is slightly more permeable than the lower zone. Overall, the Chesney lease zone permeabilities are greater than the Hegberg lease zone permeabilities. Although there is geological reason to separate the reservoir into two zones, these zones have almost identical fluid flow properties. Thus, there appears to be no reason to separate the reservoir into two layers for simulation purposes.

The core permeability data for the project were divided into four groups. Geological criteria were employed to separate these data into upper and lower zones. Each zone was further separated according to the lease it was in, the Chesney lease or the Hegberg lease. Each of these four groups has a permeability distribution with a single, asymmetric peak. This asymmetry is due to the large number of samples with low permeability that creates a long "tail" on the low permeability side of the peak. If the data below 100 millidarcies are discarded, the remaining data for each group have permeability distributions with single, symmetric peaks. These new permeability distributions are nearly log-normal. Permeability distribution properties of these four groups are presented in Table F4. Each group contains approximately the same percentage (21-33 percent) of

samples that have permeability below 100 millidarcies. If these low permeability data are discarded, all four groups have similar mean and log-mean permeabilities and nearly identical Dykstra-Parsons permeability variance coefficients.

Table F4 also includes the mean permeabilities and the Dykstra-Parsons coefficients that were obtained when the low permeability data were included in the calculations. In every group, inclusion of the low permeability data caused large changes in both the mean permeability and the Dykstra-Parsons coefficient. The distribution of the low permeability data appears to be significantly different from that of the rest of the reservoir data and may represent regions that will not produce oil during the chemical flood. The Dykstra-Parsons coefficients were calculated only to gain insight into the degree of heterogeneity present in the reservoir. They will not be used in recovery calculations. Instead, the core data on a foot-by-foot basis will be used for this purpose.

Gridded porosity, thickness, permeability, and oil saturation data for the project area have been obtained from contour maps. These data will be used in a finite-difference reservoir model study of the effects of reservoir heterogeneities on reservoir pressure distribution.

Well injectivity improvement. The superposition-of-line-source-solutions model was employed to simulate the injectivity test for well MP-213. Well MP-213 is located in an unusually thin part of the reservoir. The formation is thicker in all directions away from the well. The model predicted how the well rate would change with time for constant pressure injection into a uniform homogeneous reservoir. A two-dimensional coning model was used to predict how the rate would behave if the reservoir thickness increased with distance from the well. These two simulations were used in the analysis of the MP-213 injectivity test.

A modification of the four 6.4 acre five-spot pattern was studied as a possible solution to the problem of low injectivity into well MP-213. The modified pattern had a central 3.2 acre five-spot that was rotated 45 degrees from the original 6.4 acre five-spot orientation. Inclusion of this small five-spot changed the four 6.4 acre five-spots into irregular shaped 5.6 acre six-spots. In the modified pattern, well MP-213 was the production well for the small five-spot. A plot of streamlines and flood fronts for this pattern showed early surfactant slug breakthrough and poor sweep efficiency. Further work on this modified pattern was abandoned.

The superposition-of-line-source-solutions reservoir simulator was employed to evaluate several stimulation techniques for the central wells of each pattern, wells MP-118 and MP-213. It was assumed that the ratio of actual well rates before and after stimulation would equal the ratio of the calculated rates before and after stimulation. This study included the effects of all other wells in the project. Explosive stimulation was simulated by increasing the effective well bore radius from the actual radius of 0.333 feet to values of 0.75, 1.50, and 3.00 feet. Twinning of well MP-213 was simulated by adding another well 30 feet to the east of well MP-213 and adding the rate of the new well to the rate of MP-213. Whenever both twinning and explosive stimulation were simulated, the effective radius of both well MP-213 and its twin were increased. Increasing the injection pressure into well MP-213 (and its twin well) from 400 to 500 psia was also investigated. When the injection pressure into well MP-213 and its twin well was increased to 500 psia, the pressures for all other injection wells remained at 400 psia. The predicted actual well rates for well MP-213 for a variety of stimulation techniques are presented in Table F5. These predicted rates indicated that twinning,

explosive stimulation, and 500 psia injection pressure would all be required to achieve target injection rates into the central injector of the Hegberg lease (well MP-213 and its twin well, well MP-226).

Setting well operating conditions. The superposition-of-line-source-solutions model was used to compute time-varying well rates for constant pressure operating conditions. The injection well pressures were 400 psia and the production well pressures were 30 psia. Image wells were used to simulate reservoir boundaries. This calculation attempted to account for the low injectivity into well MP-213 by simulating it as a single rather than a twinned well. Table F6 shows the average rates for each of the Chesney wells for 18 time periods. Note that the average rate changes from one time period to the next time period. The rate of a well in the Hegberg pattern will be the same as the rate of the well in the equivalent position in the Chesney pattern. Table F7 contains the Chesney well rates expressed as a percentage of the central (well MP-118) well rate for the corresponding time periods. These are referred to as "adjusted relative rates." The purpose for them was to provide a means of relating all individual well rates in the field. Table F8 contains the Chesney well rates expressed as a percentage of the total Chesney lease injection rate for the same time periods. Tables F7 and F8 are assumed to hold for the Hegberg lease with the combination of well MP-213 and its twin well, MP-226, as the reference well.

The differences between the reservoir sweep patterns in the project area and the reservoir sweep patterns in an infinite array of five-spots will make the recovery from this project different from the recovery for a field-wide expansion. To evaluate the effects of relative well rates, a study was conducted to compare project reservoir sweep

patterns and oil recovery with the results for an infinite array of five-spots. Figures F-1 through F-6 illustrate the well patterns and relative well rates for several of the cases that were investigated. The scales of these figures were varied to show as much detail as possible. All patterns shown in these figures are 6.4 acres in size and thus have 528-foot sides. The negative numbers are injection well rates, and the positive numbers are production well rates. These rates are expressed as percentages of the average production well rate.

The base case (Case I) was a single five-spot at the center of the large array of five-spots as shown in Figure F-1. A large scale project expansion should give results similar to the base case. Figure F-2 illustrates Case II, an isolated five-spot with one-to-one total injection-to-production rate ratio. Figure F-3 illustrates Case III, an isolated five-spot with a four-to-one total injection-to-production rate ratio. The entire El Dorado project with a total injection-to-production rate ratio of two-to-one, Case IV, is shown in Figure F-4. Figure F-5 shows Case V, the project with the rates obtained with stabilized operating conditions (stabilized rates). All production well pressures were 30 psia and all injection wells had equal pressure. The injection pressure for this case was adjusted to make total injection equal total production.

Figure F-6 shows Case VI, the project with the planned well rates. These are the rates that resulted when a constant 400 psia injection pressure and a constant 30 psia production pressure were used in the simulator. This operating condition caused the well rates to vary with time. The rates used in this study were the average rates for the period from one to five years after the start of injection. They were determined from values shown in Table F6. The total injection-to-production rate ratio for this case was 1.04 to 1.

Plots of streamlines and flood fronts were prepared for each case. The flood fronts were plotted at the times when total cumulative fluid production equaled 0.1, 0.2, 0.3, etc. of the confined pore volume. Figure F-7 illustrates the region denoted by dotted lines in the center of Figure F-1. It shows the sweep and flood-front patterns expected for Case I. This should be very similar to the sweep pattern in the interior of a field-wide expansion. Figure F-8 illustrates the flood fronts and streamlines for an isolated five-spot with one-to-one total injection-to-production rate ratio (Case II). Figure F-9 illustrates the flood fronts and streamlines for an isolated five-spot that has a four-to-one injection-to-production rate ratio (Case III). Figure F-10 illustrates the sweep in the entire project when Case IV rates are used. Although these relative rates give a sweep very similar to that of the base case within the confines of the injection patterns, a large area outside the patterns is also swept by fluids. Only part of the oil that will be mobilized in the region outside the patterns is produced.

Figure F-11 illustrates flood fronts and streamlines for the project when stabilized-rate operating conditions (Case V) were used. Figure F-12 shows the fronts and streamlines for the planned operating conditions (Case VI). The flood front locations in Figure F-12 occur at the same cumulative production as the flood front locations in Figure F-11. This indicates that the areal sweep obtained with greatly increased well rates (Case VI) do not differ significantly from the areal sweep obtained for the stabilized-rate operating condition (Case V).

The major differences in the streamline and flood-front plots are in the regions outside of the confines of the five-spot patterns. The

cases with large injection-to-production ratios have numerous streamlines that flow away from the patterns. In cases with this ratio near one, most of the streamlines that initially flow away from the patterns eventually curve back to a production well. Within the confines of the patterns, the streamlines and fronts for most cases look similar to the base case. The planned operating conditions case and the stabilized-rate case agree fairly well with the base case in these confined regions. Several cases with injection-to-production ratios of one gave poor agreement in the confined regions. Plots for these cases are not illustrated.

As mentioned above, some streamlines that flow through regions outside the pattern curve back to a production well. This indicates that a portion of these external regions will be swept by injection fluid. A computer program was written to estimate the total volume of reservoir pore space swept. This program calculates the cumulative amount of original reservoir fluid produced as a function of either time, cumulative injection, or cumulative total production. This amount of original reservoir fluid produced is a measure of the reservoir pore space that is effectively swept. The curves output by this program show that the reservoir volume swept for some of the cases is greater than the total reservoir pore volume within the confines of the pattern. This effect is well known for a balanced, isolated five-spot. A way of illustrating this effect is to plot the fraction of injection fluid contained in the production stream versus cumulative total production. The cases with greater reservoir sweep will produce more original reservoir fluid and thus have lower injection fluid cuts.

Figure F-13 illustrates the differences in injection fluid cut for an infinite repeating five-spot, an isolated five-spot with one-to-one rate ratio, and an isolated five-spot with four-to-one total rate ratio.

Note that the four-to-one rate ratio isolated five-spot performance is almost identical to the performance of an infinite array of five-spots. The one-to-one rate ratio isolated five-spot has performance that is quite different from an infinite array of five-spots.

Figure F-14 compares the injection fluid cut for Case IV with the injection fluid cut for the base case. The performance of the project under these operating conditions is almost identical to the base case. However, previous work indicates that a two-to-one injection-to-production rate ratio will cause rapid increases in the average reservoir pressure in the project area. Because of the low fracture initiation pressure, the injection well rates will have to be cut back as the average reservoir pressure climbs. When this is done, the production well rates must also be cut back to maintain a two-to-one total injection-to-production rate ratio. Even after the well rates have been cut back, the net overinjection will continue to cause pressure buildup. Thus, all well rates will have to be periodically cut back throughout the project life. The capability to calculate how much this repeated cut back of well rates will extend project life is not currently available. However, the rate of reservoir pressure increase was calculated for a three-to-two production-to-injection rate ratio with constant well rates. On the basis of this calculation, it was estimated that project life with these rates would be substantially longer than project life under the stabilized-rate operating conditions (Case V). The stabilized-rate operating conditions gave a project life that is 60 percent longer than that given by the planned (overinjection) operating conditions. Thus, the two-to-one injection-to-production rate ratio would result in an unacceptably long project life. Also, the two-to-one injection-to-production rate ratio operating conditions would require

considerably more chemicals and produce less oil than the planned operating conditions.

Figure F-15 shows the performance of the project under the stabilized-rate operating conditions (Case V) and Figure F-16 shows the project performance under the planned operating conditions (Case VI). The performances for these two operating conditions are quite similar. Both have greater areal sweep than the base case. However, the excess pore volume swept for these two cases will be a smaller percentage of the total confined pore volume than the percentage excess pore volume swept for a balanced, isolated five-spot (Case II). For Cases V and VI most of the excess oil production due to this sweep of exterior pore space occurs late in the project life. In addition, the excess pore volume will be swept by a relatively small quantity of chemical slug. Thus, the oil recovery from the regions outside of the confines of the patterns will probably be less than the oil recovery from the confined pore volume. The percentage increase in oil recovery due to the sweep outside the confines of the project injection patterns will probably be less than the percentage increase in swept pore volume due to these effects. The primary objection to this outside sweep is that the increased oil recovery will make the results of the project optimistic. A program is presently being developed to calculate quantitatively the effects of this outside sweep on oil recovery. This program will eliminate the optimistic effects of outside sweep when scaling up project results to a full-scale flood.

Recovery forecast. Recovery forecasts were made for a configuration of four 6.4 acre five-spot patterns with a twinned central injection well located on the Hegberg test site. The superposition-in-time-and-space-of-line-source-solutions model was modified to automatically handle image wells while calculating well rates for constant well pressure

operating conditions. This modified model was used to predict the change of well rates versus time for the four 6.4 acre five-spot patterns with a twinned central injection well. The second central injection well was placed 30 feet to the east of the original central well. Image wells were employed to simulate reservoir boundaries a half mile to the west and a mile to the east of the pattern center line. The flowing bottom-hole pressures for the producers were held at 30 psia while the injectors were held at 400 psia. All wellbore skins were assumed zero, and the effects of the other (Chesney) four 6.4 acre five-spot patterns were included in the simulation. The well rates that were predicted for these operating conditions exhibit considerable variation with time.

An attempt to include the effects of time-varying well rates in the recovery prediction proved unexpectedly difficult. The work on time-varying streamlines was abandoned, and the recovery was calculated according to the following description. Most of the variations in well rates occur in the first 100 days after start of the overinjection operating condition. Since the preflush will take approximately 113 days to inject at the forecasted well rates, most of the rate variations will occur during the preflush period. The predicted rates change very little after the start of soluble oil (micellar solution) injection. The average rate of each well was computed for the period between 113 days and 3650 days. In every case, the maximum difference between the time-varying well rate and its average value was small. The recovery prediction program requires streamline data for the period starting with soluble oil injection and extending through the life of the project. Since the well rates change so little during this period, the streamlines for the average well rates were employed. The errors introduced by this approximation are very small.

These recovery predictions were revised by replacing the twinned central injection well with a single well. The field performance of this twinned central well is actually no better than the idealized single well simulated by the stream-tube recovery program.

A second, revised recovery prediction was made when the rates used in the previous simulation were discovered to be significantly higher than measured rates under similar operating conditions. The model had predicted a total average injection rate of 1002 barrels per day and a total average production rate of 970 barrels per day for the period after the start of micellar slug injection.

Field experience indicates that the maximum actual total injection rate for the Hegberg pattern would be about 800 barrels per day and 900 for the Chesney pattern. The ratio of total injection to total production for the previous simulation was 1.04. If this ratio were maintained in the new simulation, the total production rate would be 769 barrels per day. Instead, a total production rate of 800 barrels per day was used. The difference of 31 barrels per day of production will have little influence on the results. Operating under overinjection conditions is still recommended. However, after three or four months of overinjection, the well rates will become almost balanced. The balanced rates were used only to simplify the recovery simulation.

The relative well rates from the previous simulations are almost the same as the relative well rates for stabilized-rate operating conditions. The rates for the new simulation were set equal to 1.3557 times the stabilized rates. This results in a total injection rate and total production rate of 800 barrels per day.

Several stream-tube recovery program parameters were changed in this revised oil recovery prediction. The new parameter values conform

to the revised confined pore volume and oil-in-place values. The results of this second revised oil recovery prediction are presented in Table F9 for the Hegberg and Table F10 for the Chesney patterns. The left column is the time elapsed since start of micellar slug injection.

Surfactant slug size. In a layered reservoir with no vertical communication, the relative quantity of chemical slug entering an individual layer is a function of the thickness, the porosity, and the permeability of that layer. Thus, if these properties are known for all the layers, one can easily obtain the vertical sweep efficiency. Even though a reservoir has good vertical communication between layers, this vertical communication can be neglected to obtain an estimate of vertical sweep efficiency. This technique was applied to the foot-by-foot core and log analysis data for well MP-223. These calculations indicated that the vertical sweep efficiency in the vicinity of this well would be approximately 68 percent.

A stream-tube reservoir simulator was developed for a layered reservoir with no vertical communication. This program is based on the techniques discussed above. A two layer description of the 650-foot reservoir was developed for this simulator. The reservoir properties of the two layers (zones) are discussed above in the reservoir heterogeneity subsection. Work with this simulator was temporarily abandoned when the two layers were found to have almost identical properties.

An ideal two-dimensional areal flood that is propagated from one well to another does not sweep all of the pore volume uniformly as does an ideal one-dimensional linear flood. A program was written which uses stream-tube data to calculate the quantity of surfactant slug that passes through each portion of the reservoir. This program assumes piston-like displacement. The quantity of surfactant slug that passes through a portion of the reservoir is divided by the total quantity of fluid that

must pass through the same portion of the reservoir before the slug finally reaches a production well. The quotient is an effective fractional slug size for that portion of the reservoir. If a fixed quantity of chemical slug is injected in a pattern, the effective slug size will vary with location in the reservoir. The program calculates the total reservoir pore volume that is swept with an effective slug size greater than or equal to some specified pore volume fraction. This total pore volume is a function of both the specified fraction and the total quantity of slug injected. The program prepares a plot of the total reservoir pore volume swept as a function of both the specified fraction and the total quantity of slug injected.

This program should be very useful in future slug design. When pilot tests are run with little or no overinjection, a part of the slug will sweep oil from regions outside the confines of the pilot. This program can be used to help estimate the total swept area to be used in the slug size calculations.

At the time the slug size was estimated for the Hegberg pattern, this program was not available. The total invaded area for this flood was estimated to be 1.34 times the confined pore volume. The factor 1.34 accounts for the invaded region outside the confines of the pattern and is based on streamline and flood-front plots.

Polymer slug size. The displacement efficiencies of three polymer slug designs were evaluated with a two-dimensional polymerflood simulator. The purpose of the calculations was to ensure that the relative mobility of the polymer slug was less than the total relative mobility of the stable oil-water bank flowing ahead of the chemical slug. Before discussing

the results of the simulation study, it is important to understand how the minimum mobility of the oil-water bank used in the simulation study was determined.

The subject of mobility control design for miscible-type waterfloods using micellar solutions has been adequately described by Gogarty et. al.² The mobility requirement of a micellar solution process is fixed by the mobility of the oil and water flowing ahead of the micellar slug. Two methods are suggested for determining the total mobility of the oil-water bank. The first method calculates the minimum mobility based on relative permeability curves, while the second method relies on laboratory chemical flooding results. Both techniques were used with comparable results (see the section "Chemical Selection and Support").

The total relative mobility in the field was calculated from the relative permeability curves and pressure transient data as follows. A buildup test from Chesney well 195 indicated an effective mobility of 47.5 md/cp. This together with the air permeability of 350 millidarcies obtained from the permeability contour maps gives a total relative mobility of 0.136 cp^{-1} . The water and oil rates prior to the buildup test were 155 and 5 bbl/day, respectively. From the imbibition fractional flow curves, the reservoir water saturation was then estimated for this water cut to be 62 percent.

Figure F-17 shows the total relative mobility as a function of water saturation for Sample Number 2 from well MP-124. This sample had an air permeability of 633 md. (The relative permeability curves from which these curves were calculated were obtained by the steady-state method and are shown in Figure B-60 of the First Annual Report.) Note that the imbibition curve has a value of 0.132 cp^{-1} at a water saturation of 62 percent, a close match with the number calculated above. This curve

indicates a minimum relative mobility of about 0.075 cp^{-1} at a water saturation of 51 percent. However, since the drainage curves give a lower total relative mobility than the imbibition curves (0.022 cp^{-1} at a water saturation of 42 percent), mobility for the simulation study was based on the lower value, i.e., the drainage curves.

The displacement calculations were made with a two-dimensional polymerflood simulator to investigate how much a given polymer slug would be dispersed. Since this simulator does not model the miscible flow behavior of the micellar fluids being displaced by the polymer slug, it was necessary to ignore the micellar slug and assume that the oil-water bank forms immediately in front of the polymer slug. Thus, it was the mobility of the oil bank, not the oil saturation, which was important in this simulation.

The total relative mobility used in the modeling was 0.03 cp^{-1} at an initial oil saturation of 53 percent. This is the same as one value determined in laboratory core flood tests. However, with continued polymer injection the oil saturation ahead of the polymer slug increased until the total relative mobility reached the minimum value of 0.022 cp^{-1} at an oil saturation of 59 percent.

One-half of a confined, 6.4 acre, homogeneous five-spot was modeled. A parallel grid orientation was used in all the runs and numerical dispersion was taken into consideration. Polymer adsorption onto the rock was assumed to be 30 lb/ac-ft, a relatively low value.

Three designs for grading the polymer slug concentration were investigated, one of which was proposed by a process vendor. The results showed that the vendor's design was adequate for mobility control purposes.

Monitoring

Performance monitoring has concentrated on well condition evaluation and on data base development. Well condition evaluation has included a check on the accuracy with which reservoir pressure can be calculated from injection data and the development of the capability to plot and analyze Muskat³ and Hall⁴ plots for injection wells. Data base development included writing a program to efficiently store injection and production data and a program to retrieve and display the data in graphical or tabular form.

Monitoring well pressure. Two static bottom-hole pressure surveys of monitoring wells have been run. The first one was run early in December, 1975, after severe loss of injectivity was experienced. The survey showed a drop in reservoir pressure (up to 20 psia) caused by loss of injectivity. The results of that survey were used to check the ability of the superposition-of-line-source-solutions program to forecast reservoir pressure. It is discussed in detail below. The second survey was run in April, 1976. Due to a measurement error, the pressures were all low by an undetermined amount. Even so, monitoring well pressures showed an average increase of 83 psi over the previous values. Because of the measurement error, the second survey was not used in any calculations.

The superposition program was run assuming a homogeneous reservoir. Reservoir properties used for each lease are shown in Table F11. The permeability-thickness product used in the calculations was taken from pressure transient test results. Average values from buildup tests on the producing wells are shown in the table. Injection and production well pressures were held constant at values shown in Table F11. The results are also shown in the same table. These calculations showed three interesting points.

First, the computed injection and production rates averaged over all wells compare very well with the observed values for December 3, 1975. Second, the agreement between calculated and observed monitoring well pressures is not as good. However, considering the simplifying assumptions made in the calculations, even this agreement can be considered good. At any rate, the program forecast a decreasing pressure as was measured in the field. Third, the computed rates were sensitive to the permeability-thickness product used in the calculations, but the monitoring well pressures were not. Based on the computations discussed above, it appears that about 880 md-ft and 490 md-ft are descriptive of the flow capacity of the Chesney and Hegberg leases, respectively.

Injection well damage. A program was written to draw Hall and Muskat plots for each injector. The purpose of the work was to find a reliable method for continuous and easy evaluation of wellbore conditions using the routinely available data.

Muskat plots should be reliable until interference between adjacent oil (or water) banks takes place. Since the El Dorado reservoir has no gas saturation, this happens very early in the life of the injector. For this reason the Muskat plots were difficult to interpret. The permeability-thickness product was computed for the better behaved wells. They are compared in Table F12 to values from pressure transient tests and from core analyses.

Although Hall plots only give skin factor, the values they yielded compared favorably with other estimates. Table F13 shows the skin factor for each injector during the first week of injection (November 18-25, 1975), the first week of December, 1975, and the first week of April, 1976, as calculated from Hall plots. The three time periods

correspond to slightly damaged, severely damaged, and acidized wellbore conditions. Only four of the plots could be interpreted for the first case. The Hall plot skin factors are compared in Table F13 to those calculated from pressure transient tests for the first two time periods. The agreement is acceptable. Thus, it appears that Hall plots will be useful in monitoring injection well conditions.

Injection data plotting program. The purpose of this work was to provide graphs and summary tables of injection well data. That goal was met by a simple plotting program which was enlarged to include a summary table capability to aid in the production of monthly reports. The El Dorado plotting system (ELD-PLOT) consists of a group of four job steps, two of which use the main plotting program.

The data input for the system is from cards which are hand coded from the printed daily production/injection summaries. The data code include a date, a sort code, a well number, and a pressure and rate. This data is then sorted by well location and supplied to ELD-PLOT to produce the plots showing pressure, injection rate, and cumulative injection for each injection well of each pattern. A separate summary plot for each pattern is also drawn. In addition the user may receive Hall and Muskat plots for each well to aid in the evaluation of well performance. Normally, the data will then be resorted and again fed to ELD-PLOT for the production of well and pattern summary tables.

Data base. The El Dorado data base system (EDDE) was designed to provide for easy data analysis. It captures all data currently on the daily report. It is being expanded to allow storing of other information concerning the micellar and polymer slugs which are to be injected later. The entry facilities are both simple and powerful and allow a user with only an hour or two of instruction to begin entering data. The extraction

features are now being enhanced to allow the retrieval of any kind of information stored either to the requesting user's console or to a disc file for later access by the user's own programs. A retrieval feature is also being added to allow the transfer of the monthly injection and production well test reports to ERDA automatically, although probably in an off-line mode. Figure F-18 gives a general idea of the input-output configuration of the data base system which was written in a highly portable superset of FORTRAN known as SFTRAN.

The data are organized into four major groups. These are "Injection," "Production," "Miscellaneous," and "Operator's Notes." Data in each group are organized in a daily fashion. Information about the entry and date of last update to that data group is also provided.

Injection data consists of daily well rates, daily well pressures, master meter rate, master meter pressure, and various other metering rates inside the injection plant. In addition, any time a master meter rate is displayed, a sum of the well rates is also shown for material balance purposes. Production data is in the form of production well tests that show the oil and water production and pumping characteristics for 24-hour test periods. Miscellaneous data consists of information on chemical properties of the slug currently being injected and information about total produced fluids. The fourth section of operating notes is designed to allow a block of text information to be included to explain exceptional occurrences during daily operations.

The current retrieval facilities are being expanded to allow for at least four types of reports in addition to the normal daily report now available.

Program Development

Superposition-of-line-source-solutions models. One of the superposition-of-line-source-solutions reservoir models includes superposition in time. This model is used to compute the time-varying well rates that result when the flowing bottom-hole pressures are held constant. A second superposition-of-line-source-solutions reservoir model can only calculate reservoir and well pressures when all wells have constant rates. The development of these models was described in the First Annual Report. The constant well pressure model was modified to automatically handle the image wells that are used to simulate reservoir boundaries. Next, both of these programs were combined into a single new program. This new program allows the well specifications to change with time. For any given time period, the user may either specify all well rates or all flowing bottom-hole pressures. Rates may be specified for some time periods and flowing bottom-hole pressures for the other periods. The mathematical analyses that will permit a more general specification of rates for some wells and pressures for others within any given time period have been completed. The new programs will permit more accurate simulation of actual project operating conditions. This new model was modified to incorporate anisotropic permeability.

Flood-front and streamline tracking model. The flood-front and streamline tracking model was documented with internal comment statements. These statements describe the input data and explain the operation of the program. A copy of this program was submitted to the United States Energy Research and Development Administration for dissemination to the public.

A mathematical analysis of the effects of anisotropic permeability on point tracking calculations is over three-fourths completed. This analysis will allow the effects of anisotropic permeability to be included in the flood-front and streamline tracking model.

Stream-tube and recovery models. The mathematical analysis of point tracking in a reservoir with anisotropic permeability is also applicable to the model that calculates stream-tube data for recovery predictions. Thus, this analysis will enable calculation of the effects of anisotropic permeability on chemical flood performance.

A new program was developed to calculate stream-tube data for a homogeneous layered reservoir that has no vertical communication between layers. First, the individual layer properties are used to calculate the properties of a single equivalent layer. Second, the original stream-tube program is used to generate stream-tube data for the equivalent single layered reservoir. Third, the new program uses these single layer stream-tube data to compute the stream-tube data for the multilayered reservoir. The recovery prediction program has been modified to produce additional tables and plots of reservoir performance.

Heterogeneous Reservoir Model

A single-phase, compressible-liquid, finite-difference simulator is being used to study the effects of reservoir heterogeneities on the project. (This simulator was not developed as part of the project.) It is planned to use this simulator in conjunction with the superposition-of-line-source-solutions model to study well rates and reservoir pressures.

Computer routines are being developed that will use the pressures output by this finite-difference simulator to track fluid flow in a heterogeneous reservoir. If this work is successful, the point tracking model and the multilayer model will be modified to include the effects of reservoir heterogeneities.

A paper describing the performance predictions for the El Dorado Project was presented at the Improved Oil Recovery Symposium of the Society of Petroleum Engineers in Tulsa, Oklahoma last March.⁵

Future Work

The following objectives have been set for next year:

1. Finish development of the slug size calculation program with residual oil saturation after chemical flooding as a function of slug size.
2. Finish development of programs to include reservoir heterogeneity in the calculations.
3. Incorporate non-unit mobility ratio displacement calculation capability into the streamline and recovery programs.
4. Maintain and improve the data base and the associated programs.
5. Evaluate concentration and salinity data from observation wells.
6. Evaluate pressure data from monitoring and active wells.

References

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ENGINEERING AND OPERATIONS

OPTIMUM PATTERN DECISION

by

R. J. Miller

Summary

The pattern configuration initially chosen for the demonstration project was four contiguous 6.4 acre nine-spots. However, in July, 1975, it was concluded that four contiguous 6.4 acre five-spots would provide a more uniform breakthrough, a better sweep, and would be easier to control.

Introduction

Many pattern configurations using the existing 50 wells with minimal additional drilling were evaluated before choosing an array of four 6.4 acre five-spots. (A well layout is shown in Figure G-39 in Appendix G.) This section summarizes the main reasons for selecting the four 6.4 acre five-spot patterns. Additional discussion was included in the "Develop Optimum Pattern" section, the "Performance Prediction" section, and the "Pattern Pressure Transient Tests" section of the last annual report.¹ The section on "Pattern Pressure Transient Tests" in this report gives details concerning the closely related subject of directional permeability.

Discussion

The two basic patterns which were under consideration as the optimum pattern were four 6.4 acre five-spots (north-south and east-west lines between injection wells) and five 3.2 acre five-spots (lines between injection wells 45 degrees from north-south or east-west lines). (These pattern orientations are depicted in Figures E-1 and E-2 in Appendix E.) Many factors were considered before deciding on the optimum pattern. Some of these factors are discussed in the next subsections.

Economic Considerations

An economic analysis was made comparing the confined 6.4 acre five-spot and the confined 3.2 acre five-spot patterns. It was concluded

¹Rosenwald, G. W. and R. J. Miller (editors), El Dorado Micellar-Polymer Demonstration Project (First Annual Report). Oak Ridge, Tennessee: United States Energy Research and Development Administration, Report No. BERC/TPR-75/1, October, 1975.

that the 6.4 acre five-spot pattern would provide the most favorable economics for field-wide development.

The basic economic disadvantage of developing on 3.2 acre five-spots versus 6.4 acre five-spots was the additional cost of drilling more wells and installing more injection lines. The same recovery efficiency was assumed for both patterns. Oil would be produced in a shorter time period for the 3.2 acre five-spot configuration. Given these conditions, the economics were more favorable for the larger, 6.4 acre five-spots. One of the prime objectives for this demonstration project has been to determine if oil can be commercially realized from a micellar-polymer process. Thus, based on the discussed economic considerations, the 6.4 acre five-spot was chosen as the optimum pattern for field-wide development. To avoid the scale-up problems discussed below, a 6.4 acre five-spot was also selected for the demonstration project.

Directional Permeability Contrasts

Interference tests were run on each 6.4 acre quadrant of the project area. The prime objective of these tests was to determine the degree of directional permeability existing in the patterns. The details of these tests are described in the section "Pattern Pressure Transient Tests." It was concluded that an array of 6.4 acre five-spot patterns would provide a more uniform sweep than 3.2 acre five-spot patterns. This conclusion was based on the permeability contrasts in each quadrant.

Scale-up Problems

One of the basic objectives of this project has been to demonstrate the technical and economic feasibility of the process. It was, therefore, advantageous to utilize the same sized pattern in the demonstration project as was anticipated for expansion. There was concern

that selection of any other pattern could cause potential scale-up problems. This concern included uncertainty about the effect of the length of flow path, chemical retention, and time on the activities of the various chemicals. Some also felt that the larger pattern size better assured that the volume of the reservoir flooded be large enough to have the heterogeneity averaging influence that is generally present in the reservoir.

It was concluded that most scale-up problems could not be completely solved until the demonstration project was essentially completed, although evaluating data collected from the observation wells would be helpful. (See the section "Observation Wells" for information concerning these wells.) In order to eliminate scale-up problems, it was decided to use the four 6.4 acre five-spots for the demonstration project.

Overall Project Timing

The primary advantage of selecting the five 3.2 acre five-spots rather than the four 6.4 acre five-spots was that the project life would be reduced by approximately one-half. Obviously, the total project life was dependent on the pattern injection rate. Based on a pattern injection rate of 900 barrels per day, the pattern life was calculated to be about six and one-half years for the four 6.4 acre five-spots. It was decided that the time period for the larger pattern was reasonable for the demonstration project.

Several meetings were held in-house, with process vendors, and with ERDA personnel to discuss the advantages and disadvantages for each of the previously discussed factors. After careful consideration, it was decided by Cities Service personnel to use four 6.4 acre five-spots.

Future Work

Injection has begun in the four 6.4 acre five-spot patterns. No future work is planned for this area.

PATTERN INJECTION AND PRODUCTION

by

R. J. Miller

Summary

Injection of the salinity adjustment fluids was initiated in all 18 injection wells of both the Chesney and Hegberg patterns on November 18, 1975. A severe injection rate decrease was experienced during the first week in almost all wells. Several causes of the initial injectivity problems were identified or considered likely. These included barium sulfate formation and poor water quality. As a result of the initial injectivity problems and continuing problems in this area, the water quality testing program has received considerable emphasis. This water testing program was set up to monitor injected fluids on a daily basis.

Even after many of the initial causes or possible causes of injectivity loss had been eliminated, injectivity problems remained. As the weather became warmer, bacteria growth was identified as a contributor to the continuing injection problems. Therefore, a program of monitoring and controlling bacteria growth was initiated in the first part of 1976. A well stimulation program, which has not been completed, was started in this reporting period.

Introduction

This section discusses the background, problems, and solutions related to the pattern injection and production. The five types of injection fluids are: (1) pretreatment fluid, (2) preflush fluid, (3) micellar fluid, (4) polymer drive fluid, and (5) water drive fluid. This annual report will discuss the first phase of injection--the pretreatment and preflush.

Discussion

Fluid Production

Pumping of the production wells was started prior to injection in order to establish production history and to collect fluid for the "phased" injection period (discussed in the next subsection). The collected fluids were analyzed for suspended and dissolved solids. The analyses indicated the presence of barium and sulfate ions in the fluids from individual wells. Barium sulfate scale found in the heater-treater and water tank prompted the addition of a scale preventive at the header. See the "Chemical Selection and Support" section for more details.

After injection was initiated, production well fluid levels were measured at least once per week. The objective of monitoring the fluid levels was to keep the wells in a "pumped-off" condition which would guarantee a maximum of 30 feet of fluid in the wellbore. Obviously, the pumping rates for the production wells were increased periodically as the reservoir pressure increased. The monthly production data shown in Table G2 reflect the fluid increases corresponding to the changes in pumping rate. It should be pointed out that the oil production is below the economic limit. Therefore, any increase in oil production after injecting the micellar slug will truly be tertiary oil.

Fluid Injection Start-Up

Prior to initiating injection of the chemical preflush in the Hegberg pattern, it was decided to establish individual well rates with a pretreatment fluid. This "start-up" fluid also provided an opportunity to test the injection plant equipment. The pretreatment was designed as a wellbore clean-up fluid which is essentially a divalent-ion free brine of a low to moderate salinity designed to free the area around the wellbore from polyvalent cations. Since the in-situ brine contained approximately 90,000 milligrams per liter total dissolved solids, the low salinity pretreatment fluid injection was preceded by injection of a "phased" fluid beginning on November 18, 1975, and lasting for four days. Injection fluid consisted of 75 percent El Dorado brine and 25 percent filtered El Dorado Lake water (EDRW) the first day. The fluid was mixed at a ratio of 50 percent El Dorado brine and 50 percent EDRW for the remaining three days prior to pretreatment injection.

The same four-day phased injection sequence was used for the Chesney lease. The preflood (preflush) injection for the Chesney pattern was started on the fifth day (November 22, 1975). The chemical preflush injection for the Hegberg pattern was to start in June, 1976.

The individual well rates were throttled to approximately 100 bbl/day (barrels per day) during the first week of injection. However, during the second week, the pressure increased to near the "caution" level for fracture extension (0.74 pounds per square inch per foot of depth). After the caution pressure level was reached, the individual well rates in both patterns decreased sharply from 100 bbl/day to approximately 50 bbl/day. The injection pressures and rates versus time are shown in Figures G-1 and G-2 for the Chesney and Hegberg patterns. Similar plots

for each injection well are shown in Figure G-3 through G-20. Daily rate, pressure, and volume data are shown for each well in Tables G5 through G22. Tables G3 and G4 summarize this injection information for the two patterns.

Well Stimulation

Chemical methods. Considerable effort was expended to determine causes and solutions for the injectivity problems. A list of many possible causes was outlined and evaluated. A first step in the solution of the problem was to swab fluid from an injection well (MP-120) and analyze the solids content. The analysis indicated 12,667 mg/l (milligrams per liter) total suspended solids which consisted of the following: organics (42 percent), iron oxide (44 percent), barium sulfate (11 percent), and clay (1 percent). It was concluded that the problem was probably due to a combination of the possible causes listed below:

1. Fines movement (clays)
2. Bacteria growth
3. Barium sulfate precipitation (solids plugging sand face and/or in-situ precipitation)
4. Plugging with iron oxide
5. Emulsion plugging
6. Suspended particles in the water (which would include 2, 3, or 4 above).

Both chemical and mechanical well stimulation methods were considered before choosing two wells (MP-116 and MP-205) for a solvent-acid treatment and two wells (MP-130 and MP-215) for a wellbore surfactant treatment. The well stimulations are summarized in Table G1. The table shows that the combination solvent-acid job proved much more effective than the surfactant treatment. Based on that analysis, it was decided

to treat all of the injection wells with the following four stage solvent-acid treatment:

Stage One - 200 gallons xylene

Stage Two - 250 gallons hydrochloric acid (HCl) with demulsifier

Stage Three - 1000 gallons hydrofluoric acid (HF) with demulsifier

Stage Four - 250 gallons hydrochloric acid (HCl) with demulsifier

The preliminary results of the four stage treatment are very favorable. Injection rates and pressures will continue to be closely monitored and evaluated. If the final results prove only moderately successful, then a larger volume treatment will be considered.

Explosive methods. Four injection wells, MP-110, 223, 213, and 226 were explosively stimulated prior to pretreatment during 1975. The stimulation technique was implemented for two reasons:

1. Satisfactory injectivity had not been achieved by under-reaming, acidizing, open-hole perforating, or combinations of these methods.
2. Explosive stimulation creates a larger effective wellbore radius by extension of mini-fractures whereas hydraulic fracturing creates a single planar fracture which can result in bypassing portions of the reservoir and premature breakthrough at the production wells.

The explosive stimulation application used a series of three pound solid charges (on a wireline) which could be detonated from the surface. A casing collar locator was used to correctly place the charges. After stimulation was complete, the well was swabbed and bailed for a minimum of four hours. A tracer survey was then run to confirm that fluids were not channeling above or below the 650-foot Sand.

The explosively stimulated wells did not experience the initial severe rate decrease that generally occurred in the other injectors. However, some injectivity loss did occur later and progressive fouling is in evidence.

Hydraulic fracturing methods. Hydraulic fracturing has been considered the last resort for stimulating injection wells since bypassing of some of the reservoir could occur. On the other hand, a production well could be fractured with minimal reservoir bypassing.

Two wells, MP-114 and MP-207, produced only 23 and 29 barrels of fluid per day, respectively. A buildup test was run on well MP-114 in order to measure the flow capacity (kh) and wellbore damage (skin factor). However, the low production rate unreasonably extended the period required to get enough pressure drawdown for accurate measurement during the subsequent buildup period. It was estimated from the data obtained that the permeability was much higher than that found in MP-207 and the formation damage factor (skin) was approximately +20. Although MP-207 also had a low production rate, it was possible to run a buildup test because the low formation permeability gave enough pressure drawdown in a reasonable time to enable an accurate measurement. The pressure buildup test run on MP-207 gave a formation permeability of 18.3 md and a skin factor of +5.7. An acid job and a solvent treatment were both unsuccessful in decreasing the wellbore damage in well MP-114. It was then decided to perform a small fracture treatment in both MP-114 and MP-207.

The frac job consisted of 1000 gallons of gelled formation water and 500 pounds 20-40 sand. The fracture treatment (based on a horizontal rather than vertical fracture) was designed to create a fracture width of 0.042 inch and a calculated propped radius of 66 feet. The post-frac production rates for MP-114 and MP-207 were 51 and 49 bbl/day, respectively.

Injection Profiles

Three methods of monitoring injection profiles were investigated for the open-hole completed injection wells. The packer-flowmeter method was chosen as the most practical means of determining an injection profile for an open-hole interval with no rat hole.

The packer-flowmeter tool consisted of an inflatable packer, a packer pump, and a turbine meter with surface read-out equipment. The tool was run on a wireline to a point just above the casing packer shoe in order to inflate the packer and establish 100 percent flow below the packer. The packer was deflated, lowered, and inflated every one to two feet while simultaneously measuring fluid injection below the packer setting. The percent of fluid per foot was then calculated and graphed for individual wells. Individual well profiles are shown in Figures G-21 through G-38 in September, 1975 (prior to injection).

Water Quality

In a micellar-polymer flood it is essential to maintain proper water quality. It is not desired to increase the injectivity by simply raising the injection pressure above the pressure corresponding to the formation fracture gradient. One method to help avoid operating above the fracture pressure is to remove as many suspended solids as practical from the injected fluids.

The initial plan to monitor water quality in the El Dorado Micellar-Polymer Project was to test the source-water turbidity from the sand filter and filter all components mixed with the water through in-line cartridge filters. After the severe rate decrease was experienced during the first week of injection, it was decided also to monitor water quality by a millipore filter apparatus. The permanently mounted filter apparatus

was installed with direct lines to all injected fluid sources. The tests have been made by filtering a measured volume of fluid (usually three liters) through 0.45 or 1.2 micron millipore filter paper while applying 20 pounds per square inch (psig) pressure. The filtration rate versus time was recorded.

One criterion for a good quality water has been to have an initial flow rate of about 10 ml/sec (milliliters per second) with a rate still above 4 ml/sec after three liters have passed through a 0.45 micron filter. Another criterion was to weigh a millipore filter paper before and after passing a measured volume of fluid through the paper. Generally, less than one milligram per liter was considered good quality water. A third criterion described in a paper by Barkman and Davidson¹ is to calculate a water quality ratio which could be used to relate to formation impairment. The water quality ratio was defined as the ratio of the concentration of suspended solids to the permeability of the filter cake formed by those solids.

Water quality tests were run daily on filtered fresh water, saturated salt water, and the injected fluid mixtures. The initial water quality tests were considered good for the filtered fresh water and saturated salt water. However, the test showed poor results for the injected fluid mixtures. Typical membrane filter residue analyses are shown in Table G24. The analysis indicated that a large percentage (ranging from 17-67 percent) of the total solids were organic in nature. Subsequent water testing indicated both aerobic and anaerobic bacteria were present in the source water.

¹Barkman, J. H. and D. H. Davidson, "Measuring Water Quality and Predicting Well Impairment," Journal of Petroleum Technology, 25: 865-873, July, 1972.

Since March 17, 1976, chlorine gas has been injected into the fresh water line at the pump station to control bacteria. The chlorine is maintained at 6-8 ppm (parts per million) with "slugs" at 40 ppm. About three weeks later a bacteria count showed a decreased but unacceptable level. Since increasing the chlorine rate would reduce the effectiveness of the polymer flocculant used in the sand filter, it was decided to add a trichlorinated phenol with amine acetate in the injection plant starting April 29, 1976. It was not desirable to add the toxic phenol at the pump station because the effluent of the fresh water filter flush was accessible to livestock. The effectiveness of the combination chlorine-phenol treatment has not been completely evaluated.

Future Work

Injection of the chemical preflush was to have been initiated in the Hegberg pattern in June, and should be completed during the next reporting period. Chesney preflush will continue long into the next reporting period.

If sufficient fluid injectivity can be maintained during the next reporting period, micellar fluid injection can be initiated into both patterns. Both larger acid treatments and explosive stimulations will be reviewed to help maintain fluid injectivity. As a last resort, hydraulic fracturing may be considered. Additional packer flowmeter injection profiles will be run during and after preflush injection. Water quality will be improved by reducing bacteria counts to a maximum of 10-100 colonies per milliliter.

OBSERVATION WELLS

by

R. J. Miller

with

H. L. Chang

Summary

Four observation wells were completed in February, 1976. Although not originally planned, observation wells were considered necessary to provide sufficient data to evaluate the micellar-polymer process for the purpose of future expansion.

Introduction

The complex nature of a micellar-polymer process requires a field test for the transfer of laboratory developed technology into a field-wide operation. Valuable field information such as the effectiveness of preflush and oil displacement, chemical losses, micellar slug propagation, and polymer performance are needed to support and expand laboratory findings. Observation wells located close to the injection wells should be an effective method of evaluating the design parameters and accurately appraising the process.

Discussion

There were four observation wells completed in 1976. Wells MP-131 and MP-132 were located 90 and 187 feet, respectively, southwest of the central injector in the north pattern (well MP-118). As shown in Figure G-39, wells MP-227 and MP-228 were located 90 and 187 feet, respectively, southwest of MP-213. The observation wells were drilled as a combination of sampling and logging wells. Air was used to drill to a point about 50 feet above the Admire Sand. The rest of the well was drilled and cored with formation water. Table G23 gives detailed well data.

A base open-hole log suite was run before setting casing. A string of five and one-half inch steel casing with 90 feet of fiberglass casing on the bottom was run in the borehole and cemented to surface. A second open-hole type log was run to check any tool response to the fiberglass casing. Careful analysis of the two logs indicated that the fiberglass casing did not cause any change in formation characteristics. The fiberglass casing was perforated with four bullets in a one foot interval in order to collect reservoir fluid samples. One-inch hollow sucker rods were run inside two-inch steel tubing with a packer to pump a small volume of fluid for daily analysis.

The analysis should provide the following information for each injection phase:

1. Preflush - Some chemicals in the preflush are generally adsorptive and are partially consumed as they flow through the reservoir. Although laboratory experiments are performed to determine the chemical consumption, the question of representative rock samples, scaling techniques, and experimental methods are debatable. The fluid analysis from the observation wells taken at a known time and distance from the central injector should provide information on the effectiveness of the preflush. The concentration profile for various chemical species can not only be used to calculate preflush slug size for future project expansion but should also indicate the adequacy of the preflush slug sizes selected for the demonstration project.
2. Micellar - The primary information that can be gained from observation wells during the injection of the micellar slug is the effectiveness of the chemical slugs (surfactant and polymer). Other information such as the change of fractional flow, the type of any emulsion that may form, the viscometric characteristics of displaced and displacing fluids, and the multivalent ion content in the micellar slug can also be obtained. These valuable data are generally difficult to collect from production wells due to the long flow path the fluids have followed.
3. Polymer - Polymer adsorption, inaccessible pore volume, interaction with sulfonates, retention, and degradation are important questions that can be partially answered by data taken from sampling and logging observation wells.

Future Work

Fluid samples will be taken and analyzed daily from all four observation wells. Based on fluid analysis, periodic logs will be run to determine vertical conformance of each fluid phase.

CONSTRUCTION
FRESH WATER SYSTEM AND INJECTION PLANT

by

R. J. Miller

Summary

Both the fresh water system and injection plant were essentially completed in 1975. Some minor modifications have been scheduled for the injection plant in 1976. Except for some freezing problems, which were eliminated as quickly as possible, the injection plant has performed satisfactorily.

Introduction

The fresh water system must deliver a continuous high quality water to the injection plant. The purpose of the injection plant is to measure, mix, and deliver chemicals to the distribution system.

Discussion

The El Dorado city drinking water source was chosen as the most desirable water for the demonstration project. There are three potential water sources for city drinking water: (1) Lake Bluestem, (2) Lake El Dorado, and (3) the east branch of the Walnut River. The city of El Dorado has generally taken its drinking water from Lake Bluestem. However, during drought conditions or dam repairs Lake El Dorado and Walnut River water have been used. Since the pipeline to the demonstration project intersects the city water supply line above the Walnut River outlet, only Lake El Dorado water was analyzed as a substitute water source.

The water analysis for Lake El Dorado indicated the total calcium and magnesium content to be 63 mg/l as compared to 33 mg/l for Lake Bluestem water. The total dissolved solids content was 300 mg/l for Lake El Dorado compared to 171 mg/l for Lake Bluestem water. The higher calcium and magnesium content has been taken into consideration before adding chemical softening agents whenever it has been necessary to use the substitute water source. Using the Lake El Dorado water has also required some adjustments in the filtering of the raw water.

The six-inch PVC line that provided fresh water to the upflow sand filter was completed in August, 1975. Some minor modifications were made to the fresh water pump station in order to inject chlorine gas in

March, 1976. (See the section "Pattern Injection and Production" for details.)

The injection plant was essentially completed and ready for injection in November, 1975. There were relatively few problems associated with the initial plant start-up. However, severe freezing problems were experienced during December, 1975, and January, 1976. All exposed exterior lines had to be heat taped and wrapped with insulation. It even became necessary to install a building over the fresh water filter skid to prevent freezing of the quiescent fresh water in lines and pumps.

The upflow sand filter has generally provided a moderately good quality fresh water. Quality criteria are described in the section "Pattern Injection and Production." Some problems were initially experienced in adjusting the correct polymer flocculant rate. Since it was basically a trial-and-error procedure, a data bank of raw water turbidity versus polymer rate had to be developed.

An additional problem occurred when the chlorine gas was introduced at the pump station. The liquid polyacrylamide polymer tested as the optimum polymer flocculant was not compatible with chlorine. In order to "re-optimize" the polymer flocculant, additional tests were conducted to select a chlorine resistant flocculant. The new polymer has been undergoing a complete evaluation.

Future Work

Modifications to the injection plants that will be made in the coming year include the following:

1. Install and hook up additional mixing systems for some minor chemical additives that were not originally expected to be necessary.

2. Connect in-line heaters to heater loops.
3. Order and install polymer mixing equipment.
4. Design and install well test unit.
5. Install additional final stage fluid filtering apparatus when needed.

PART II
APPENDIX A
CHEMICAL SELECTION AND SUPPORT
Tables and Figures

TABLE A1

TOTAL MOBILITY AND TOTAL RELATIVE MOBILITY OF OIL-WATER BANK

DETERMINED IN EL DORADO CORES

Run No.	Core Identification		Air Permeability millidarcies	λ_T 1/cp	M_T darcy/cp
	Well	Depth feet			
1	MP-219	672	247	0.025	0.0062
2	MP-219	671	1069	0.018	0.0188
3	MP-120	627	258	0.045	0.0116
4	MP-130	637	540	0.065	0.0348

 λ_T = Total relative mobility M_T = Total mobility

TABLE A2

ANALYSES OF PRODUCED WATER FROM WELLS MP-114 AND MP-207

<u>Dissolved Solids* and Other Properties</u>	<u>Well MP-114</u>	<u>Well MP-207</u>
Sodium, Na ⁺	26173	25596
Calcium, Ca ⁺⁺	2628	2129
Magnesium, Mg ⁺⁺	1971	1748
Barium, Ba ⁺⁺	0	0
Strontium, Sr ⁺⁺	118	117
Chloride, Cl ⁻	49518	49780
Sulfate, SO ₄ ⁼	1950	88
Calculated TDS**	84332	80775
pH	6.3	6.4
Specific gravity, g/ml	1.068	1.060

*Dissolved solids in parts per million

**Total dissolved solids

FIGURE A-1
RESULTS OF OIL DISPLACEMENT TESTS WITH
SHELL CHEMICAL FORMULATIONS
IN BEREA CORES AND EL DORADO 650-FOOT
SANDSTONE CORES

FIGURE A-2

EFFECT OF SOLUBLE OIL ON POLYMER VISCOSITY

AT ROOM TEMPERATURE AT A SHEAR

RATE OF 7.4 SEC^{-1}

(Nalco Polymer Q41F, lot 5228)

FIGURE A-3
OBSERVATION WELL LOCATIONS

FIGURE A-4

SALINITY CHANGE VS THROUGHPUT OF PRETREATMENT

SLUG FOR WELL MP-131

*Based on a cylinder from well MP-118 to MP-131 using adjusted ϕh and corrected for the 31.27 percent S_{or} in the Chesney Pattern.

APPENDIX B
CORING AND CORE ANALYSES

Tables and Figures

TABLE B1
WHOLE CORE PERMEABILITIES VS DEPTH
FOR WELL MP-112

<u>Depth feet</u>	<u>North-South Permeability millidarcies</u>	<u>East-West Permeability millidarcies</u>	<u>Remarks</u>
608-15	-	-	Shale
615-16	30	25	
616-17	62*	29*	
617-18	148*	136*	
618-19	276	261	
619-20	32	26	
620-21	422	387	
621-22	325	321	
622-23	329	310	Orientation not known
623-24	357	326	Orientation not known
624-25	160*	139*	
625-26	-	-	Lost core
626-27	238	234	Orientation not known
627-28	32	30	
628-29	218	210	
629-30	667	667	
630-31	-	-	Unsuitable for analysis
631-32	671	632	
632-33	580	580	
633-34	473	466	
634-35	689	657	
635-43	-	-	Shale
643-44	-	-	Lost core

*Denotes plug permeability

TABLE B2
 ROUTINE CORE ANALYSIS RESULTS VS DEPTH
 FOR WELL MP-114

Depth feet	Permeability To Air millidarcies	Porosity percent	Grain Density g/ml	Bulk Density g/ml	Fluid Saturations percent		Comments
					Oil	Water	
639.0	1.1	19.6	2.75	2.21	6.0	76.3	Shaley, Not in avg. Sand Sand
640.0	178.0	23.2	2.69	2.07	50.8	32.3	
641.0	95.0	23.4	2.68	2.05	33.5	38.7	
642.0	25.0	22.0	2.68	2.09	56.7	29.9	Sand
643.0	131.0	25.0	2.68	2.01	11.1	9.7	Sand
644.0	183.0	25.7	2.67	1.98	30.0	45.5	Sand
645.0	522.0	29.2	2.67	1.89	25.1	52.5	Sand
646.0	492.0	28.7	2.67	1.90	24.3	42.9	Sand
647.0	698.0	29.7	2.67	1.88	18.7	45.7	Sand
648.0	367.0	27.5	2.67	1.93	26.0	50.0	Sand
649.0	479.0	27.4	2.67	1.94	25.6	44.6	Sand
650.0	960.0	29.1	2.66	1.89	31.7	32.6	Sand
651.0	183.0	26.1	2.67	1.98	33.3	42.8	Sand
652.0	256.0	25.9	2.66	1.98	39.0	37.9	Sand
653.0	700.0	27.4	2.66	1.93	35.6	48.5	Sand
654.0	744.0	29.4	2.67	1.89	20.9	59.7	Sand
655.0	153.0	24.5	2.68	2.02	28.3	52.4	Sand
656.0	Broken	21.6	2.72	2.13	18.5	72.9	Shaley sand
Averages	385.4	26.2			29.9		

TABLE B3
WHOLE CORE PERMEABILITIES VS DEPTH
FOR WELL MP-126

<u>Depth feet</u>	<u>North-South Permeability millidarcies</u>	<u>East-West Permeability millidarcies</u>	<u>Remarks</u>
650-55	-	-	Shale
655-56	170	190	
656-57	143	135	
657-58	155	150	
658-59	182	177	
659-60	228	205	
660-61	230	206	
661-62	295	275	
662-63	273	251	
663-64	116	123	
664-65	249	217	
665-66	178	149	
666-67	190	182	
667-68	160*	303*	
668-69	148*	647*	

* Denotes plug permeability

TABLE B4
ROUTINE CORE ANALYSIS RESULTS VS DEPTH
FOR WELL MP-128

Depth feet, inches	"C" Sample					"D" Sample
	Grain Density g/ml	k _{air} md	Porosity percent	S _o ¹ percent	S _w percent	k _{air} md
649 3	2.691	94.1	25.9	33.5	53.0	36.1
649 10	2.679	15.7	22.9	37.7	54.2	13.4
650 2	2.688	82.2	24.3	42.2	48.6	63.0
650 6	2.700	94.8	24.1	36.8	52.2	58.6
650 10	2.686	188	26.1	32.2	63.8	148
651 6	2.694	88.3	24.5	36.8	58.9	95.0
651 8	2.683	896	28.5	37.1	47.8	740
651 11	2.681	727	28.7	33.3	56.9	602
652 3	2.677	648	28.1	33.7	57.5	547
652 9	2.746	51.1	13.7	34.2	63.9	44.9
653 4	2.699	204	22.8	37.3	55.4	121
653 7	2.680	465	26.9	27.3	59.4	190
654 0	2.680	370	27.8	23.9	66.5	278
654 3	2.689	60.7	22.7	37.8	58.8	52.1
654 7	2.674	510	28.0	22.6	73.7	451
655 0	2.679	216	25.9	29.4	63.8	150
655 4	2.683	321	28.0	33.4	59.2	257
655 8	2.687	469	27.9	33.7	59.6	473
656 3	2.588	42.3	23.0	37.2	61.9	46.9
656 7	2.682	376	28.0	28.8	65.2	280
657 0	2.688	491	28.9	26.1	71.4	419
657 6	2.678	409	27.7	19.8	75.0	308
658 6	2.681	265	26.8	31.5	65.8	235
659 0	2.661	321	26.9	28.0	63.3	254
659 4	2.661	48.2	24.0	20.7	71.5	-
659 8	2.676	148	26.2	26.8	68.8	85.1
659 10	2.684	412	28.3	30.1	60.5	318
660 3	2.686	229	27.2	37.0	58.7	170
660 6	2.683	220	26.7	31.8	64.0	235
660 10	2.685	324	26.8	36.2	55.6	300
661 8	2.683	313	27.5	36.7	61.7	217
662 2	2.682	620	28.7	32.8	63.8	424
663 6	2.675	800	28.8	39.6	57.1	785
664 0	2.669	1280	29.9	32.9	59.0	855
665 2	2.678	439	27.6	34.0	55.2	275
665 10	2.682	422	27.3	38.1	60.4	-
666 5	2.679	719	29.1	36.0	59.1	566
667 2	2.674	709	29.1	31.8	63.2	-
667 8	2.677	892	28.3	34.0	56.2	795
668 2	2.681	859	29.1	37.3	55.3	705
668 7	2.690	676	28.4	40.8	51.3	650

¹Based on an assumed oil density of 0.841 g/cc.

All measurements were made on one-inch diameter plugs. The "C" and "D" samples were drilled side-by-side, essentially in the same bedding planes. Where obvious, the sample appearing to be the most homogeneous was selected as the "C" sample.

TABLE B5
ROUTINE CORE ANALYSIS RESULTS VS DEPTH
FOR WELL MP-207

Depth feet	Permeability To Air millidarcies	Porosity percent	Grain Density g/ml	Bulk Density g/ml	Fluid Saturations percent		Comments
					Oil	Water	
655.5	2.6	9.1	2.72	2.51	1.9	79.4	Shale, Not in avg.
656.3	0.02	6.8	2.73	2.54	1.3	27.1	Shale, Not in avg.
657.7	0.03	12.4	2.68	2.37	8.7	62.0	Shale, Not in avg.
658.4	179.0	26.8	2.74	2.00	8.7	5.8	Sand
659.2	275.0	24.7	2.73	2.06	28.8	27.9	
660.0	188.0	28.8	2.76	1.97	7.8	31.2	
661.3	385.0	27.1	2.73	1.99	23.3	16.6	Sand
662.0	450.0	17.0	2.77	1.89	41.9	25.9	Sand
664.4	150.0	10.0	2.70	2.16	18.6	29.0	Sand
665.3	276.0	32.3	2.85	1.93	7.6	13.9	Sand
666.7	338.0	30.7	2.79	1.93	17.7	14.7	
668.0	0.0	7.6	2.70	2.50	25.1	70.4	Shale, Not in avg.
669.6	206.0	30.0	2.77	1.94	15.4	15.5	Sand
670.2	224.0	29.4	2.77	1.95	12.7	20.9	Sand
671.5	381.0	28.0	2.74	1.97	10.5	20.6	Sand
672.2	550.0	31.6	2.79	1.91	1.1	25.2	Sand
673.1	678.0	32.7	2.79	1.88	10.8	21.3	
674.0	Broken	30.3	2.70	1.88	12.3	21.9	Shaley sand
675.2	19.6	21.8	2.76	2.15	5.0	44.7	Shaley sand
676.3	Broken	19.6	2.72	2.19	22.1	41.0	
677.0	221.0	25.2	2.78	2.08	7.4	35.8	Sand
Averages	301.4	26.8			14.8		

TABLE B6
WHOLE CORE PERMEABILITIES VS DEPTH
FOR WELL MP-211

<u>Depth feet</u>	<u>North-South Permeability millidarcies</u>	<u>East-West Permeability millidarcies</u>	<u>Remarks</u>
648-56	-	-	Shale
656-57	20	21	
657-58	101	124	
658-59	-	-	Unsuitable for analysis
659-60	178	181	
660-61	89	67	
661-62	165	162	
662-63	323	313	
663-64	282	269	
664-65	411	381	
665-66	-	-	Unsuitable for analysis
666-68	-	-	Lost core
668-70	-	-	Unsuitable for analysis
670-71	354	329	
671-72	374	318	
672-73	36	27	
673-74	475	441	
674-75	-	-	Unsuitable for analysis
675-76	483	377	
676-77	-	-	Shale
677-78	148	156	
678-80	-	-	Shale

TABLE B7
PERMEABILITY AVERAGES AND DYKSTRA-PARSONS ANALYSES
FOR EL DORADO PROJECT CORES

	<u>Chesney Pattern Ten Cores</u>	<u>Hegberg Pattern Ten Cores</u>	<u>Test Wells Five Cores</u>
<u>All Data Points</u>			
Median, md	408	230	305
Geometric Average, md	160	52	168
Arithmetic Average, md	429	325	367
Number of Data Points	195	195	141
<u>Points Greater Than 10 md</u>			
Median, md	434	331	332
Geometric Average, md	336	257	249
Arithmetic Average, md	473	414	394
Number of Data Points	177	153	131
<u>Points Greater Than 100 md</u>			
Median, md	490	385	415
Geometric Average, md	465	405	396
Arithmetic Average, md	541	498	484
Number of Data Points	152	125	104
Dykstra-Parsons Variance Factor	0.424	0.475	0.463

TABLE B8
WETTABILITY DETERMINATION FOR CORE PLUGS
FROM DIFFERENT LOCATIONS

<u>Sample Description</u>		<u>Wettability</u>
<u>Well</u>	<u>Depth, ft</u>	
MP-114	644.4	-0.19
MP-114	644.5	-0.21
MP-124	647.8	-0.06
MP-124	647.9	-0.11
MP-209	664.4	0.03
MP-209	664.5	0.06
MP-217	686.6	0.02
MP-217	687.3	0.00

TABLE B9
WETTABILITY DETERMINATION FOR
HEATED AND UNHEATED CORE PLUGS

Unheated Cores			Heated Cores		
<u>Sample Description</u>			<u>Sample Description</u>		
<u>Depth, ft</u>	<u>Plug</u>	<u>Wettability</u>	<u>Depth, ft</u>	<u>Plug</u>	<u>Wettability</u>
641.0	Bottom	-0.55	641.0	Top	-0.33
641.6	Bottom	-0.42	641.6	Top	-0.38
641.9	Bottom	-0.48	641.9	Top	-0.30
642.9	Bottom	-0.58	641.8	Top	-0.33

TABLE B10
SUMMARY OF WATER-OIL RELATIVE PERMEABILITY TESTS
STEADY-STATE TECHNIQUE

	<u>Well MP-124</u>	<u>Well MP-124</u>	<u>Well MP-124</u>	<u>Well MP-217</u>	<u>Well MP-217</u>	<u>Well MP-217 (Extracted)</u>
Depth, feet	651.9	656.1	660.0	665.0	665.0	665.0
Air Permeability, md	393.0	343.0	475.0	183.0	232.0	232.0
Water Permeability, md	365.0	337.0	399.0	166.0	206.0	206.0
Porosity, percent	27.9	27.1	27.7	26.3	26.9	26.9
<u>Water Saturation Increasing</u>						
Initial Water Saturation, percent	31.5	40.9	33.8	32.0	31.6	28.7
Initial Oil Permeability, millidarcies	347.0	229.0	476.0	80.0	136.0	155.0
Residual Oil Saturation, percent	17.2	25.9	20.4	24.5	22.0	23.1
Water Permeability at Floodout, md	185.0	94.0	191.0	36.0	40.0	43.0
<u>Oil Saturation Increasing</u>						
Initial Oil Saturation, percent	17.2	25.9	20.4	24.5	22.0	23.1
Initial Water Permeability, millidarcies	185.0	94.0	191.0	36.0	40.0	43.0
Final Water Saturation, percent	22.4	25.6	23.3	32.3	35.6	28.7
Oil Permeability, md	312.0	190.0	469.0	83.0	52.0	147.0

TABLE B11
END POINT SATURATIONS FOR IMBIBITION AND DRAINAGE FLOODS
USING CORE FROM WELL MP-124

Depth feet	Oil Type	Oil Permeability At Connate Water millidarcies	Connate Water Saturation percent	Residual Oil Saturation percent	Water Permeability At Residual Oil millidarcies	Residual Water Saturation percent	Oil Permeability At Residual Water millidarcies
647.5	S-130*	159	31.2	16.2	78	-	-
647.4	S-130	137	29.0	16.0	62	-	-
650	S-130	603	15.7	19.8	247	21.7	426
651 #1	Carnation	66	24.4	20.7	11	20.6	68
651 #2	Carnation	31	18.0	21.1	8	18.9	28
651 #3	Chesney Crude	283	15.8	24.0	136	-	-
656.8	Chesney Crude	7	26.0	29.1	3	-	-
Extracted Cores							
638.4	S-130	119	29.0	28.1	43	23.1	164
637.6	Carnation	437	24.7	26.5	87	17.6	419

* Soltrol 130

TABLE B12

DISTRIBUTARY CHANNEL, INTERTIDAL, AND SPLAY CHANNEL
SUBENVIRONMENT THICKNESSES AND PERCENTAGES FOR THE
ADMIRE 650-FOOT SANDSTONE IN THE PROJECT AREA

Well Number	Sandstone Gross Thickness feet	Distributary Channel		Intertidal		Splay Channel	
		No. of Feet	Percent of Pay	No. of Feet	Percent of Pay	No. of Feet	Percent of Pay
MP-101	20	14	70	3	15	3	15
MP-102	24	21	88	1.5	6	1.5	6
MP-103	20	15.9	80	2	10	2	10
MP-104	21	16	76	1.5	7	3.5	17
MP-105	21	12	57	5.5	26	3.5	17
MP-106	20	16.5	83	2.5	12	1.0	5
MP-110	20.5	13	63	4.5	22	3.0	15
MP-112	16	7	44	5.5	34	3.5	22
MP-116	19.5	15	77	1.5	8	3	15
MP-120	18.6	12.6	68	2.5	13	3.5	19
MP-122	15	8	53	5.0	33	2	14
MP-126	16	16	100	0	0	0	0
MP-128	20.5	14	68	2.5	12	4	20
MP-130	19.4	14.4	74	3.0	15	2	11
MP-201	19.4	14.4	74	1.5	8	3.5	18
MP-203	17.7	13.2	75	2.0	11	2.5	14
MP-205	20.8	13.8	66	4.0	20	3	14
MP-211	21	14	67	5.0	23	2	10
MP-213	12	7	58	2	17	3	25
MP-215	21	11	52	4.5	22	5.5	26
MP-221	20	14.5	73	3.5	17	2	10
MP-223	18	7.5	42	5.5	30	5.0	28
MP-225	22	13	59	5.5	25	3.5	16

Relative Permeability , fraction

TABLE B13
SEMIQUANTITATIVE X-RAY DIFFRACTION ANALYSIS
FOR CORE FRAGMENTS
OF THE LESS-THAN FIVE MICRON SIZE FRACTION

<u>Well MP-201</u> <u>Depth, feet</u>	<u>Percent less</u> <u>than 5μ</u>	<u>Illite</u>	<u>Illite-</u> <u>Montmorillonite</u>	<u>Chlorite</u>	<u>Kaolinite</u>	<u>Calcite</u>	<u>Quartz</u>
657	9.1	11	3	4	17	-	65
665	8.1	18	3	5	17	-	57
673	9.5	16	2	6	15	-	62
<u>Well MP-211</u> <u>Depth, feet</u>							
660	8.9	17	2	4	19	-	57
667	7.7	20	4	6	18	-	51
674	8.0	20	3	6	17	-	54
<u>Well MP-213</u> <u>Depth, feet</u>							
674.5	10.2	26	4	6	20	1	43
677	8.0	15	3	5	14	-	63
680	12.1	30	4	10	19	-	37
<u>Well MP-215</u> <u>Depth, feet</u>							
650	9.2	18	3	7	12	-	60
656	9.1	21	4	7	17	-	51
664	7.3	14	2	5	14	-	65
<u>Well MP-221</u> <u>Depth, feet</u>							
662	7.8	40	5	1	39	10	10
663	30.0	30	10	15	40	-	5
664-667	5.9	35	-	10	45	5	5
668-672	6.6	25	5	15	40	5	10
673-674	8.4	30	-	10	50	-	10
675	7.0	30	-	15	45	-	10
677-680	8.9	35	-	-	45	5	10
<u>Well MP-223</u> <u>Depth, feet</u>							
672	9.7	19	2	6	15	-	59
679	7.7	20	3	7	17	-	53
684	9.4	16	2	6	15	-	62
<u>Well MP-225</u> <u>Depth, feet</u>							
657-658	13.6	45	5	10	20	10	10
659	6.8	40	15	10	20	-	15
660	16.2	55	15	10	10	-	10
660.4-662.0	7.4	45	10	10	20	5	10
664	7.1	40	15	10	25	-	10
665-666	8.7	50	10	10	25	-	5
667	6.1	40	10	15	20	-	5
668-669	11.0	50	10	15	20	-	5
669.8	5.8	40	10	15	25	-	10
670-671	6.3	35	15	15	20	-	15
672-673	5.7	40	10	15	20	-	15
675-677	15.2	50	10	20	15	-	5
678	23.0	45	5	25	20	-	5

FIGURE B-1
DYKSTRA - PARSONS ANALYSIS OF PERMEABILITY
FOR THE CHESNEY PATTERN

FIGURE B-2
ANALYSIS OF PERMEABILITY DISTRIBUTION

FIGURE B-9
TOTAL RELATIVE MOBILITY
STEADY-STATE RELATIVE PERMEABILITY DATA

FIGURE B-10

TOTAL RELATIVE MOBILITY

STEADY-STATE RELATIVE PERMEABILITY DATA

FIGURE B-11

GEOLOGICAL CORE DESCRIPTION FOR THE
ADMIRE 650-FOOT SANDSTONE FROM WELL MP-213

LEGENDRock Types

- Carbonate rich
- Claystone or shale
- Siltstone
- Sandstone

Sedimentary Structures

- Lenticular (flaser) bedded ripples
- Wavy claystone lamination
- Climbing ripples
- Trough cross-bedding
- Deformed clay-rich trough
- Distinct burrows
- Bioturbation
- Claystone rip-up clasts
- Fossil shell fragments

FIGURE B-12
ADMIRE SANDSTONE SUBENVIRONMENTS

APPENDIX C

WELL LOGGING

Tables and Figures

TABLE C1

BASIC WELL DATA

RESULTS OF WELL LOGGING

<u>Well Number</u>	<u>Logged Interval feet</u>		<u>Gross Pay feet</u>	<u>Net Pay[*] feet</u>	<u>Elevation Above Mean Sea Level, ft</u>	
	<u>From</u>	<u>To</u>			<u>Top</u>	<u>Bottom</u>
MP-131	637.5	656.0	18.5	17.5	759.5	741.0
MP-132	641.5	658.5	17.0	13.5	756.5	739.5
MP-227	663.5	679.5	16.0	14.0	737.5	721.5
MP-228	658.0	677.0	19.0	17.0	742.0	723.0
Arithmetic Average			17.6	15.5		
Geometric Mean			17.6	15.4		

* Formation intervals having residual oil saturation less than five percent were not included in determining the net pay.

TABLE C2
RESULTS OF WELL LOGGING ANALYSES
ARITHMETIC AND WEIGHTED AVERAGES

<u>Well Number</u>	<u>Pore Volume bbl/ac-ft</u>	<u>Average Porosity percent</u>	<u>Hydrocarbon Pore Volume bbl/ac-ft</u>	<u>Average Residual Oil Saturation percent</u>	<u>Average Oil In Place percent</u>	<u>Average Movable Oil percent</u>	<u>Average Permeability Index</u>	<u>Average Clay percent</u>
MP-131	1724	22.22	439.10	24.53	24.53	0.00	36.40	14.69
MP-132	1766	22.77	279.70	15.67	15.67	0.00	36.44	16.89
MP-227	1795	23.14	559.85	30.34	30.16	0.18	42.38	20.57
MP-228	1761	22.71	420.26	23.17	23.17	0.00	37.53	9.47
Arithmetic Average	1761	22.71	424.73	23.43	23.38	0.045	38.19	15.40
Weighted Average	1760	22.68	426.49	23.54	23.50	0.04	38.07	15.06

TABLE C3
RESULTS OF WELL LOGGING ANALYSES
GEOMETRIC MEANS

<u>Well Number</u>	<u>Pore Volume bbl/ac-ft</u>	<u>Mean Porosity percent</u>	<u>Hydrocarbon Pore Volume bbl/ac-ft</u>	<u>Mean Residual Oil Saturation percent</u>	<u>Mean Oil In Place percent</u>	<u>Mean Permeability Index</u>	<u>Mean Clay percent</u>
MP-131	1708.18	22.02	368.60	21.58	21.58	31.19	11.38
MP-132	1762.14	22.71	263.52	14.95	14.95	34.20	15.54
MP-227	1775.98	22.89	501.70	28.57	28.25	34.41	17.53
MP-228	1752.57	22.59	355.44	20.28	20.28	33.90	7.63
Geometric Mean	1749.52	22.55	362.78	20.79	20.74	33.40	12.40

TABLE C4
WELL LOG DETERMINED PROPERTIES
VS DEPTH FOR WELL MP-131

WELL LOCATION: 992' FSL 2576' FWL 21 25S 5E

KELLY BUSHING ELEVATION FROM SEA LEVEL = 1397

*DEPTH	GR	POR	RT	RXO	SXO	ROS	SW	PER	CLAY	S0	MO	PHV	HPV	ELSE
637.50	87.70	14.80	4.40	5.00	95.00	5.00	95.00	9.00	44.00	5.00	.00	1148.24	57.41	759.50
638.00	82.00	19.60	4.10	4.10	72.60	27.40	72.60	18.00	15.00	27.40	.00	1520.65	416.66	759.00
638.50	80.00	20.90	3.80	3.90	70.60	29.40	70.60	18.00	15.00	29.40	.00	1621.50	476.72	758.50
639.00	76.30	22.70	3.60	3.80	66.10	33.90	66.10	35.00	13.00	33.90	.00	1761.16	597.03	758.00
639.50	72.30	22.70	3.40	3.70	68.00	32.00	68.00	35.00	13.00	32.00	.00	1761.16	563.57	757.50
640.00	70.00	23.40	3.20	3.60	68.30	31.70	68.30	40.00	9.00	31.70	.00	1815.46	575.50	757.00
640.50	68.60	23.90	3.00	3.70	69.20	30.80	69.20	40.00	9.00	30.80	.00	1854.26	571.11	756.50
641.00	66.40	24.40	2.80	3.70	70.30	29.70	70.30	48.00	3.00	29.70	.00	1893.05	562.24	756.00
641.50	64.90	24.70	2.60	3.60	71.60	28.40	71.60	48.00	3.00	28.40	.00	1916.32	544.24	755.50
642.00	66.40	25.10	2.40	3.80	72.30	27.70	72.30	54.00	3.00	27.70	.00	1947.36	539.42	755.00
642.50	66.70	25.50	2.40	4.00	72.50	27.50	72.50	54.00	3.00	27.50	.00	1978.39	544.06	754.50
643.00	65.70	25.90	2.30	3.40	71.40	28.60	71.40	62.00	3.00	28.60	.00	2009.42	574.70	754.00
643.50	67.50	25.90	2.30	3.00	71.50	28.50	71.50	62.00	3.00	28.50	.00	2009.42	572.69	753.50
644.00	64.20	25.80	2.30	2.80	72.10	27.90	72.10	62.00	4.00	27.90	.00	2001.67	558.46	753.00
644.50	67.40	24.90	2.30	3.00	74.70	25.30	74.70	62.00	4.00	25.30	.00	1931.84	488.76	752.50
645.00	71.30	24.80	2.40	3.30	74.70	25.30	74.70	52.00	11.00	25.30	.00	1924.08	486.79	752.00
645.50	73.70	24.70	2.40	3.50	73.80	26.20	73.80	52.00	11.00	26.20	.00	1916.32	502.08	751.50
646.00	75.40	24.20	2.60	3.40	73.30	26.70	73.30	47.00	14.00	26.70	.00	1877.53	501.30	751.00
646.50	81.80	19.30	2.70	3.40	91.10	8.90	91.10	47.00	14.00	8.90	.00	1497.37	133.27	750.50
647.00	82.90	18.30	2.80	3.50	94.50	5.50	94.50	14.00	27.00	5.50	.00	1419.79	78.09	750.00
647.50	83.50	18.10	2.90	4.00	94.00	6.00	94.00	14.00	27.00	6.00	.00	1404.27	84.26	749.50
648.00	78.70	22.20	3.00	4.40	74.60	25.40	74.60	32.00	12.00	25.40	.00	1722.36	437.48	749.00
648.50	77.20	24.00	3.00	4.10	68.20	31.80	68.20	32.00	12.00	31.80	.00	1862.02	592.12	748.50
649.00	77.50	23.70	3.00	3.80	68.90	31.10	68.90	42.00	11.00	31.10	.00	1838.74	571.85	748.00
649.50	82.20	20.30	3.10	3.50	80.10	19.90	80.10	42.00	11.00	19.90	.00	1574.95	313.42	747.50
650.00	85.80	17.40	3.20	3.30	93.20	6.80	93.20	11.00	21.00	6.80	.00	1349.96	91.80	747.00
650.50	88.10	15.20	3.30	3.30	100.00	.00	100.00	11.00	21.00	.00	.00	1179.28	.00	746.50
651.00	87.60	15.40	3.40	3.80	100.00	.00	100.00	6.00	27.00	.00	.00	1194.79	.00	746.00
651.50	85.50	16.90	3.40	4.30	93.40	6.60	93.40	6.00	27.00	6.60	.00	1311.17	86.54	745.50
652.00	85.20	17.50	3.50	4.70	88.50	11.50	88.50	11.00	28.00	11.50	.00	1357.72	156.14	745.00
652.50	80.50	21.00	3.60	4.50	72.20	27.80	72.20	11.00	28.00	27.80	.00	1629.26	452.94	744.50
653.00	78.00	22.60	3.70	4.30	65.80	34.20	65.80	35.00	25.00	34.20	.00	1753.40	599.66	744.00
653.50	78.70	22.30	3.70	4.10	67.00	33.00	67.00	35.00	25.00	33.00	.00	1730.12	570.94	743.50
654.00	79.00	22.30	3.50	3.90	68.40	31.60	68.40	34.00	19.00	31.60	.00	1730.12	546.72	743.00
654.50	79.00	22.70	3.40	3.80	68.70	31.30	68.70	34.00	19.00	31.30	.00	1761.16	551.24	742.50
655.00	78.80	23.20	3.20	3.80	69.00	31.00	69.00	38.00	14.00	31.00	.00	1799.95	557.98	742.00
655.50	80.70	22.00	2.90	4.00	75.90	24.10	75.90	38.00	14.00	24.10	.00	1706.85	411.35	741.50
A.AVE.	76.04	22.22	3.05	3.79	75.47	24.53	75.47	36.40	14.69	24.53	.00	1723.91	439.10	
G.MEAN	75.73	22.02	3.01	3.76	74.96	21.58	74.96	31.19	11.38	21.53		1708.18	368.60	

*NOTATION--Depth, ft; GR-Gamma Ray Index, API Units; POR-Porosity, %; RT-True Resistivity, Ohms-m²/m; RXO-Flushed Zone Resistivity, Ohms-m²/m; SXO-Flushed Zone Saturation, %; ROS-Residual Oil Saturation, %; SW-Water Saturation, %; PER-Permeability Index; Clay-Clay Content, %; S0-Oil Saturation, %; MO-Movable Oil, %; PHV-Pore Volume, bbl/ac-ft; HPV-Hydrocarbon Pore Volume, bbl/ac-ft; ELSE-Elevation From Sea Level, ft

TABLE C5
WELL LOG DETERMINED PROPERTIES
VS DEPTH FOR WELL MP-132

WELL LOCATION: 924' FSL 2508' FWL 21 25S 5E

KELLY BUSHING ELEVATION FROM SEA LEVEL = 1398

*DEPTH	GR	POR	RT	RXO	SXO	ROS	SW	PER	CLAY	SO	MO	PHV	HPV	ELSE
641.50	98.10	21.00	2.70	2.70	83.00	17.00	83.00	11.00	26.00	17.00	.00	1629.26	276.97	756.50
642.00	94.40	22.80	2.60	2.90	78.30	21.70	78.30	36.00	16.00	21.70	.00	1768.91	383.85	756.00
642.50	89.70	23.40	2.40	3.10	78.40	21.60	78.40	36.00	16.00	21.50	.00	1815.46	392.14	755.50
643.00	87.00	23.80	2.30	3.00	79.50	20.50	79.50	43.00	10.00	20.50	.00	1846.50	378.53	755.00
643.50	85.60	24.10	2.10	2.90	81.10	18.90	81.10	43.00	10.00	18.90	.00	1869.77	353.39	754.50
644.00	85.10	24.60	2.00	2.80	82.10	17.90	82.10	50.00	6.00	17.90	.00	1908.57	341.63	754.00
644.50	88.50	24.30	1.90	2.60	84.70	15.30	84.70	50.00	6.00	15.30	.00	1885.25	288.45	753.50
645.00	90.50	24.10	1.80	2.50	87.10	12.90	87.10	46.00	11.00	12.90	.00	1869.77	241.20	753.00
645.50	90.90	24.00	1.80	2.40	87.80	12.20	87.80	46.00	11.00	12.20	.00	1862.02	227.17	752.50
646.00	89.70	24.40	1.80	2.40	86.30	13.70	86.30	48.00	9.00	13.70	.00	1893.05	259.35	752.00
646.50	91.10	24.80	1.90	2.40	83.70	16.30	83.70	48.00	9.00	16.30	.00	1924.08	313.63	751.50
647.00	95.90	24.90	1.90	2.40	82.10	17.90	82.10	53.00	14.00	17.90	.00	1931.84	345.80	751.00
647.50	99.30	24.80	2.00	2.50	81.10	18.90	81.10	53.00	14.00	18.90	.00	1924.08	363.65	750.50
648.00	100.90	23.60	2.00	2.70	84.30	15.70	84.30	42.00	21.00	15.70	.00	1830.98	287.46	750.00
648.50	102.40	21.20	2.10	3.10	93.20	6.80	93.20	42.00	21.00	6.80	.00	1644.78	111.85	749.50
649.00	105.90	18.20	2.20	3.60	100.00	.00	100.00	13.00	34.00	.00	.00	1412.03	.00	749.00
649.50	105.00	17.70	2.20	3.30	100.00	.00	100.00	13.00	34.00	.00	.00	1373.24	.00	748.50
650.00	104.20	18.90	2.30	3.00	100.00	.00	100.00	16.00	27.00	.00	.00	1466.34	.00	748.00
650.50	103.40	21.40	2.30	2.60	88.60	11.40	88.60	16.00	27.00	11.40	.00	1660.30	189.27	747.50
651.00	101.50	23.40	2.30	2.50	80.00	20.00	80.00	40.00	15.00	20.00	.00	1815.46	363.09	747.00
651.50	103.00	22.00	2.40	2.70	84.60	15.40	84.60	40.00	15.00	15.40	.00	1706.85	262.85	746.50
652.00	103.90	20.80	2.40	3.00	89.60	10.40	89.60	24.00	25.00	10.40	.00	1613.75	167.83	746.00
652.50	104.80	19.80	2.40	3.20	93.90	6.10	93.90	24.00	25.00	6.10	.00	1536.16	93.71	745.50
653.00	106.70	18.20	2.40	3.30	100.00	.00	100.00	13.00	38.00	.00	.00	1412.03	.00	745.00
653.50	107.90	17.00	2.50	3.30	100.00	.00	100.00	13.00	38.00	.00	.00	1318.93	.00	744.50
654.00	106.80	17.20	2.50	3.30	100.00	.00	100.00	10.00	39.00	.00	.00	1334.44	.00	744.00
654.50	103.40	19.00	2.50	3.20	96.50	3.50	96.50	10.00	39.00	3.50	.00	1474.10	51.59	743.50
655.00	100.30	21.10	2.50	3.20	85.60	14.40	85.60	26.00	22.00	14.40	.00	1637.02	235.73	743.00
655.50	98.70	22.10	2.60	3.20	81.10	18.90	81.10	26.00	22.00	18.90	.00	1714.61	324.06	742.50
656.00	100.20	21.00	2.50	3.20	85.90	14.10	85.90	25.00	21.00	14.10	.00	1629.26	229.73	742.00
656.50	101.10	20.20	2.50	3.10	90.50	9.50	90.50	25.00	21.00	9.50	.00	1567.20	148.88	741.50
657.00	99.50	21.20	2.50	3.00	86.30	13.70	86.30	26.00	23.00	13.70	.00	1644.78	225.33	741.00
657.50	98.10	22.70	2.50	2.90	79.90	20.10	79.90	26.00	23.00	20.10	.00	1761.16	353.99	740.50
658.00	97.10	23.20	2.50	2.90	78.20	21.80	78.20	39.00	17.00	21.80	.00	1799.95	352.39	740.00
A.AVE.	96.32	22.77	2.25	2.31	84.33	15.67	84.33	36.44	16.89	15.57	.00	1766.33	279.70	
G.MEAN	96.13	22.71	2.23	2.30	84.22	14.95	84.22	34.20	15.54	14.95		1762.14	263.52	

*NOTATION--Depth, ft; GR-Gamma Ray Index, API Units; POR-Porosity, %; RT-True Resistivity, Ohms-m²/m; RXO-Flushed Zone Resistivity, Ohms-m²/m; SXO-Flushed Zone Saturation, %; ROS-Residual Oil Saturation, %; SW-Water Saturation, %; PER-Permeability Index; Clay-Clay Content, %; SO-Oil Saturation, %; MO-Movable Oil, %; PHV-Pore Volume, bbl/ac-ft; HPV-Hydrocarbon Pore Volume, bbl/ac-ft; ELSE-Elevation From Sea Level, ft

TABLE C6
WELL LOG DETERMINED PROPERTIES
VS DEPTH FOR WELL MP-227

WELL LOCATION: 592' FSL 2576' FWL 28 25S 5E

KELLY BUSHING ELEVATION FROM SEA LEVEL = 1401

* DEPTH	GR	POR	RT	RXO	SXO	ROS	SW	PER	CLAY	SO	MO	PHV	HPV	ELSE
663.50	68.60	17.30	4.20	7.20	82.10	17.90	82.10	16.50	42.00	17.30	.00	1342.20	240.25	737.50
664.00	62.00	22.40	4.50	5.30	73.00	39.60	60.40	33.00	12.00	39.50	.00	1737.88	688.20	737.00
664.50	60.20	25.30	4.50	4.40	70.00	47.20	52.80	33.00	12.00	47.20	.00	1962.88	526.48	736.50
665.00	60.00	26.30	4.30	4.30	67.60	47.90	52.10	67.00	9.00	47.30	.00	2040.46	577.38	736.00
665.50	60.80	27.00	3.90	4.40	65.20	47.10	52.90	67.00	9.00	47.10	.00	2094.77	586.63	735.50
666.00	63.50	27.30	3.50	4.50	63.70	44.80	55.20	78.00	7.00	44.30	.00	2118.04	548.88	735.00
666.50	66.10	27.30	3.20	4.40	64.60	42.50	57.50	78.00	7.00	42.50	.00	2118.04	900.17	734.50
667.00	67.90	27.40	2.90	4.00	66.90	39.90	60.10	80.00	9.00	39.30	.00	2125.80	848.19	734.00
667.50	69.60	26.40	2.70	3.70	72.90	35.00	65.00	80.00	9.00	35.00	.00	2048.22	716.88	733.50
668.00	70.60	25.40	2.50	3.40	79.00	29.90	70.10	57.00	14.00	29.30	.00	1970.63	589.22	733.00
668.50	70.80	25.30	2.40	3.10	72.60	27.40	72.60	57.00	14.00	27.40	.00	1962.88	537.83	732.50
669.00	68.60	27.50	2.20	2.80	79.70	31.70	68.30	82.00	9.00	31.70	.00	2133.56	676.34	732.00
669.50	68.80	27.40	2.10	2.90	78.80	29.70	70.30	82.00	9.00	29.70	.00	2125.80	631.36	731.50
670.00	72.40	23.10	2.00	3.10	86.60	13.40	86.60	38.00	11.00	13.40	.00	1792.19	240.15	731.00
670.50	74.50	18.90	1.90	3.30	100.00	.00	100.00	38.00	11.00	.00	.00	1466.34	.00	730.50
671.00	77.30	15.50	2.00	3.50	100.00	.00	100.00	7.00	32.00	.00	.00	1202.55	.00	730.00
671.50	79.40	13.10	2.00	3.20	100.00	.00	100.00	7.00	32.00	.00	.00	1016.35	.00	729.50
672.00	77.40	15.60	2.10	3.00	100.00	.00	100.00	7.00	30.00	.00	.00	1210.31	.00	729.00
672.50	72.60	21.40	2.40	3.10	86.80	13.20	86.80	7.00	30.00	13.20	.00	1660.30	219.16	728.50
673.00	70.70	23.60	2.70	3.50	73.40	26.60	73.40	42.00	19.00	26.50	.00	1830.98	427.04	728.00
673.50	70.00	24.50	2.90	4.00	76.00	32.50	67.50	42.00	19.00	32.50	.00	1900.81	617.76	727.50
674.00	71.60	23.10	3.20	4.40	77.50	30.60	69.40	38.00	24.00	30.50	.00	1792.19	548.41	727.00
674.50	73.90	20.50	3.50	4.60	74.90	25.10	74.90	38.00	24.00	25.10	.00	1590.47	399.21	726.50
675.00	73.80	20.10	3.70	4.60	74.10	25.90	74.10	21.00	26.00	25.30	.00	1559.44	403.89	726.00
675.50	72.70	21.20	3.90	4.60	68.90	31.10	68.90	21.00	26.00	31.10	.00	1644.78	511.53	725.50
676.00	74.10	19.70	4.00	4.50	73.40	26.60	73.40	19.00	30.00	26.50	.00	1528.40	406.56	725.00
676.50	75.90	17.90	4.00	4.40	80.90	19.10	80.90	19.00	30.00	19.10	.00	1388.75	265.25	724.50
677.00	75.00	19.00	4.10	4.30	75.40	24.60	75.40	16.00	34.00	24.50	.00	1474.10	362.63	724.00
677.50	74.00	20.50	4.00	4.30	70.20	29.80	70.20	16.00	34.00	29.30	.00	1590.47	473.96	723.50
678.00	73.70	21.10	3.90	4.20	68.60	31.40	68.60	25.00	35.00	31.40	.00	1637.02	514.02	723.00
678.50	75.20	23.20	3.90	4.20	76.60	23.40	76.60	25.00	35.00	23.40	.00	1799.95	421.19	722.50
679.00	77.10	16.70	3.90	4.10	89.40	10.60	89.40	9.00	37.00	10.50	.00	1295.65	137.34	722.00
A.AVE.	70.01	23.14	3.39	4.15	74.60	30.16	69.84	42.38	20.57	30.16	.00	1795.24	559.85	
G.MEAN	69.83	22.89	3.30	4.08	74.31	28.25	69.09	34.41	17.53	28.25		1775.98	501.70	

* NOTATION--Depth, ft; GR-Gamma Ray Index, API Units; POR-Porosity, %; RT-True Resistivity, Ohms-m²/m; RXO-Flushed Zone Resistivity, Ohms-m²/m;
SXO-Flushed Zone Saturation, %; ROS-Residual Oil Saturation, %; SW-Water Saturation, %; PER-Permeability Index; Clay-Clay Content, %; SO-Oil
Saturation, %; MO-Movable Oil, %; PHV-Pore Volume, bbl/ac-ft; HPV-Hydrocarbon Pore Volume, bbl/ac-ft; ELSE-Elevation From Sea Level, ft

TABLE C7

WELL LOG DETERMINED PROPERTIES

VS DEPTH FOR WELL MP-228

WELL LOCATION: 660' FNL 2508' FWL 28 25S 5E

KELLY BUSHING ELEVATION FROM SEA LEVEL = 1400

*DEPTH	GR	POR	RT	RXO	SXO	ROS	SW	PER	CLAY	S0	MO	PHV	HPV	ELSE
658.00	68.00	18.90	3.50	4.60	81.90	18.10	81.90	16.00	12.00	18.10	.00	1466.34	265.41	742.00
658.50	69.70	19.80	3.60	3.60	76.50	23.50	76.50	16.00	12.00	23.50	.00	1536.16	361.00	741.50
659.00	70.70	22.00	3.70	3.30	67.80	32.20	67.80	30.00	5.00	32.20	.00	1706.85	549.60	741.00
659.50	68.70	22.40	3.70	3.20	66.60	33.40	66.60	30.00	5.00	33.40	.00	1737.88	580.45	740.50
660.00	65.70	22.40	3.70	3.30	66.50	33.50	66.50	33.00	5.00	33.50	.00	1737.88	582.19	740.00
660.50	62.90	22.30	3.60	3.40	67.80	32.20	67.80	33.00	5.00	32.20	.00	1730.12	557.10	739.50
661.00	63.00	22.20	3.50	3.50	68.70	31.30	68.70	32.00	4.00	31.30	.00	1722.36	539.10	739.00
661.50	63.50	22.20	3.50	3.40	69.10	30.90	69.10	32.00	4.00	30.90	.00	1722.36	532.21	738.50
662.00	63.50	22.30	3.40	3.30	69.20	30.80	69.20	32.00	3.00	30.80	.00	1730.12	532.88	738.00
662.50	63.50	22.40	3.40	3.40	69.30	30.70	69.30	32.00	3.00	30.70	.00	1737.88	533.53	737.50
663.00	63.30	22.70	3.40	3.40	68.80	31.20	68.80	35.00	3.00	31.20	.00	1761.16	549.48	737.00
663.50	62.30	23.20	3.30	3.40	68.20	31.80	68.20	35.00	3.00	31.30	.00	1799.95	572.38	736.50
664.00	63.50	24.30	3.20	3.20	65.80	34.20	65.80	47.00	4.00	34.20	.00	1885.29	644.77	736.00
664.50	64.20	25.60	3.00	2.90	63.50	36.50	63.50	47.00	4.00	36.50	.00	1986.15	724.94	735.50
665.00	64.40	26.50	2.80	2.70	63.20	36.80	63.20	69.00	3.00	36.80	.00	2055.97	756.60	735.00
665.50	64.90	26.50	2.60	2.60	65.50	34.50	65.50	69.00	3.00	34.50	.00	2055.97	709.31	734.50
666.00	65.80	26.50	2.50	2.60	67.70	32.30	67.70	69.00	5.00	32.30	.00	2055.97	664.08	734.00
666.50	68.00	26.50	2.40	2.60	69.40	30.60	69.40	69.00	5.00	30.50	.00	2055.97	629.13	733.50
667.00	69.10	26.20	2.20	2.60	72.30	27.70	72.30	65.00	9.00	27.70	.00	2032.70	563.06	733.00
667.50	69.00	25.80	2.10	2.60	75.20	24.80	75.20	65.00	9.00	24.30	.00	2001.67	456.41	732.50
668.00	69.40	25.50	2.00	2.60	78.10	21.90	78.10	58.00	9.00	21.30	.00	1978.39	433.27	732.00
668.50	70.30	25.10	2.10	2.70	78.10	21.90	78.10	58.00	9.00	21.90	.00	1947.36	426.47	731.50
669.00	72.90	23.40	2.10	2.70	83.10	16.90	83.10	40.00	15.00	16.30	.00	1815.46	306.81	731.00
669.50	75.10	20.80	2.20	2.90	93.70	6.30	93.70	40.00	15.00	6.30	.00	1613.75	101.67	730.50
670.00	75.80	19.90	2.20	3.00	96.90	3.10	96.90	18.00	18.00	3.10	.00	1543.92	47.86	730.00
670.50	76.30	19.60	2.30	3.20	96.60	3.40	96.60	19.00	18.00	3.40	.00	1520.65	51.70	729.50
671.00	76.60	19.50	2.40	3.20	95.70	4.30	95.70	18.00	18.00	4.30	.00	1512.89	65.05	729.00
671.50	76.60	19.20	2.50	3.00	95.30	4.70	95.30	18.00	18.00	4.70	.00	1489.61	70.01	728.50
672.00	75.70	19.80	2.50	2.90	91.40	8.60	91.40	19.00	18.00	8.60	.00	1536.16	132.11	728.00
672.50	75.40	20.10	2.50	2.90	90.00	10.00	90.00	19.00	18.00	10.00	.00	1559.44	155.94	727.50
673.00	75.60	20.00	2.50	2.90	90.60	9.40	90.60	20.00	19.00	9.40	.00	1551.68	145.86	727.00
673.50	76.00	19.80	2.50	2.80	91.80	8.20	91.80	20.00	19.00	8.20	.00	1536.16	125.97	726.50
674.00	76.00	20.10	2.50	2.80	91.10	8.90	91.10	21.00	19.00	8.90	.00	1559.44	138.79	726.00
674.50	76.00	20.50	2.40	2.80	90.30	9.70	90.30	21.00	19.00	9.70	.00	1590.47	154.28	725.50
675.00	75.70	21.10	2.40	2.90	88.30	11.70	88.30	25.00	15.00	11.70	.00	1637.02	191.53	725.00
675.50	74.90	22.70	2.30	3.00	82.70	17.30	82.70	25.00	15.00	17.30	.00	1761.16	304.68	724.50
676.00	76.10	21.40	2.30	2.90	88.60	11.40	88.60	27.00	13.00	11.40	.00	1660.30	189.27	724.00
676.50	76.50	21.00	2.20	2.80	91.50	8.50	91.50	27.00	13.00	8.50	.00	1629.26	138.49	723.50
A.AVE.	69.39	22.71	2.81	3.04	76.83	23.17	76.83	37.53	9.47	23.17	.00	1761.61	420.26	
G.MEAN	69.21	22.59	2.75	3.01	76.16	20.28	76.16	33.90	7.63	20.23		1752.57	355.44	

*NOTATION--Depth, ft; GR-Gamma Ray Index, API Units; POR-Porosity, %; RT-True Resistivity, Ohms-m²/m; RXO-Flushed Zone Resistivity, Ohms-m²/m;

SXO-Flushed Zone Saturation, %; ROS-Residual Oil Saturation, %; SW-Water Saturation, %; PER-Permeability Index; Clay-Clay Content, %; S0-Oil

Saturation, %; MO-Movable Oil, %; PHV-Pore Volume, bbl/ac-ft; HPV-Hydrocarbon Pore Volume, bbl/ac-ft; ELSE-Elevation From Sea Level, ft

TABLE C8
GEOMETRIC AND ARITHMETIC AVERAGES
OF WELL LOG DETERMINED PROPERTIES
FOR OBSERVATION WELLS

WELL NO.	INTERVAL FT		GROSS PAY FT	NET PAY FT	PORE VOLUME BBL/AC-FT	GEOMETRIC MEAN						ELEVATION FROM SEA LEVEL	
	FROM	TO				G. MEAN POROSITY PERCENT	HYDROCARBON PORE VOLUME BBL/AC-FT	G. MEAN RES. OIL SATURATION PERCENT	G. MEAN OIL IN PLACE PERCENT	G. MEAN PERM. INDEX	G. MEAN CLAY PERCENT	TOP	BOTTOM
MP-131	637.50	656.00	18.50	17.5	1708.18	22.02	368.60	21.58	21.53	31.19	11.38	759.50	741.00
MP-132	641.50	658.50	17.00	13.5	1762.14	22.71	263.52	14.95	14.33	34.20	15.54	756.50	739.50
MP-227	663.50	679.50	16.00	14.0	1775.98	22.89	501.70	28.25	28.25	34.41	17.53	737.50	721.50
MP-228	658.00	677.00	19.00	17.0	1752.57	22.59	355.44	20.28	20.28	33.90	7.63	742.00	723.00
GEOMETRIC MEAN			17.58	15.4	1749.52	22.55	362.78	20.74	20.74	33.40	12.40		

ARITHMETIC AND WEIGHTED AVERAGES

WELL NO.	INTERVAL FT		GROSS PAY FT	NET PAY FT	PORE VOLUME BBL/AC-FT	AVERAGE POROSITY PERCENT	HYDROCARBON PORE VOLUME BBL/AC-FT	AVERAGE RES. OIL SATURATION PERCENT	AVERAGE OIL IN PLACE PERCENT	AVERAGE MOVABLE OIL PERCENT	AVE. PERM. INDEX	CLAY AVE. PERCENT	ELEV. FROM SEA LEVEL	
	FROM	TO											TOP	BOTTOM
MP-131	637.50	656.00	18.50	17.5	1723.91	22.22	439.10	24.53	24.53	.00	36.40	14.69	759.50	741.00
MP-132	641.50	658.50	17.00	13.5	1766.33	22.77	279.70	15.67	15.57	.00	36.44	16.89	756.50	739.50
MP-227	663.50	679.50	16.00	14.0	1795.24	23.14	559.85	30.16	30.15	.00	42.38	20.57	737.50	721.50
MP-228	658.00	677.00	19.00	17.0	1761.61	22.71	420.26	23.17	23.17	.00	37.53	9.47	742.00	723.00
ARITHMETIC AVERAGE			17.63	15.5	1761.77	22.71	424.73	23.38	23.33	.00	38.15	15.40		
WEIGHTED AVERAGE					1759.59	22.68	426.49	23.50	23.50	.00	38.07	15.06		

FIGURE C-1
 COMPENSATED DENSIOLOG
 COMPENSATED NEUTRON LOG FOR WELL MP-228

FIGURE C-2

DUAL INDUCTION FOCUSED LOG FOR WELL MP-228

OPEN-HOLE EPILOG FOR WELL MP-131

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
			RESV	DISV			
	SHALE % BULK VOLUME	WATER SATURATION %	0	100	0	100	0
	PERMEABILITY INDEX 10 ⁴	HYDROCARBON VOLUME $\phi \cdot S_{hr}$	.1	0			.25
		HYDROCARBON WEIGHT $\phi \cdot S_{hr} \cdot \rho_h$	0				.25
caliper (-) Bit Size ' <div> <div>-4</div> <div>0</div> <div>12</div> </div>

FIGURE C-4

OPEN-HOLE EPILOG FOR WELL MP-132

FIGURE C-5
OPEN-HOLE EPILOG FOR WELL MP-227

FIGURE C-6

OPEN-HOLE EPILOG FOR WELL MP-228

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
	SHALE % BULK VOLUME	WATER SATURATION %					
0	100	100	50	0	100	0	0
	PERMEABILITY INDEX	HYDROCARBON VOLUME $\phi \cdot S_{hr}$					
10^4	.10	.25					
		HYDROCARBON WEIGHT $\phi \cdot S_{hr} \cdot \rho_h$					
		0 .25					
caliper (-) Bit Size							
-4 0 12

CASED-HOLE EPILOG FOR WELL MP-131

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
	SHALE % BULK VOLUME	WATER SATURATION %					
0	100	100	0	50	0	100	0
	PERMEABILITY INDEX	HYDROCARBON VOLUME $\phi \cdot S_{hr}$					
10 ⁴	.10	.25					
		HYDROCARBON WEIGHT $\phi \cdot S_{hr} \cdot \rho_h$					
		0					

caliper (-) Bit Size

-4 0 12

FIGURE C-8

CASED-HOLE EPILOG FOR WELL MP-132

CASED-HOLE EPILOG FOR WELL MP-227

DEPTH	LITHOLOGIC CHARACTERISTICS	FLUID ANALYSIS	POROSITY AND FLUIDS % BULK VOLUME		FORMATION % BULK VOLUME		
			HYDROCARBON	WATER	CLAY	QUARTZ	POROSITY
	SHALE % BULK VOLUME	WATER SATURATION					
0	100	100 %	0 50 %	0	100	%	0
	PERMEABILITY INDEX	HYDROCARBON VOLUME $\phi \cdot S_{hr}$					
10 ⁴	.10	.25					
		HYDROCARBON WEIGHT $\phi \cdot S_{hr} \cdot \rho_h$					
		0 .25					
			caliper (-) Bit Size				
			-4 0 12

0070-1

APPENDIX D
FORMATION INJECTIVITY TESTS

Table and Figure

TABLE D1
RESULTS OF LABORATORY FLOW TESTS COMPARING
INJECTIVITY OF UNION CHEMICAL PREFLUSH
WITH AND WITHOUT A SOLUBLE OIL PRETREATMENT

<u>Core Identification</u>	<u>Test 1</u>		<u>Test 2</u>	
	Well No.	MP-106	MP-106	
Depth, ft		649	649	
k_w at S_{or} , md		294	315	
<u>Slug Sequence</u>	$\frac{Q/\Delta p}{\text{ml/hr psi}}$	<u>Pore Volumes Injected</u>	$\frac{Q/\Delta p}{\text{ml/hr psi}}$	<u>Pore Volumes Injected</u>
Chesney 195 Brine [*]	0.188	15	0.193	5
EDRW ^{**}	0.172	20	0.198	20
Union Preflush	0.010	25	-	0
Soluble Oil (50/50)	0.006	15	0.059	10
EDRW	-	0	0.181	10
Union Preflush	0.020	20	0.193	20
EDRW	-	0	0.202	10
Chesney 195 Brine	-	0	0.181	10

^{*} Produced water from Chesney well 195 (outside the test area).

^{**} EDRW stands for filtered El Dorado Raw (fresh) Water.

FIGURE D-1

INJECTIVITY TEST USING AN EL DORADO CORE PLUG

PRESSURE TRANSIENT TESTS

Tables and Figures

TABLE E1

INTERFERENCE TEST RESULTS FOR THE CHESNEY PATTERN

From Well	To Well	Δp_1^* Inches of Water	Δt_1^{**} hr	q bbl/day	$k_e h$ md-ft	h ft	k_e md	r ft	k_ϕ md
MP-123	MP-124	525	34.0	190	1393	15.5	89.9	274	18.0
MP-118	MP-124	650	14.8	190	1125	16.0	70.3	387	82.5
MP-117	MP-124	720	15.2	190	1016	18.0	56.4	274	40.3
MP-116	MP-124	700	26.0	190	1045	19.0	55.0	373	43.7
MP-125	MP-124	795	26.5	190	920	18.5	49.7	254	19.9
MP-126	MP-124	615	19.0	190	1189	18.0	66.1	359	55.3
MP-127	MP-124	870	8.4	190	841	17.5	48.1	254	62.7
MP-128	MP-124	865	16.2	190	846	17.5	48.3	374	70.5
		<u>708</u>	<u>18.5</u>		<u>1033</u>	<u>17.5</u>	<u>59.1</u>		<u>43.4</u>
MP-112	MP-114	142	64.0	25	678	17.8	38.1	548	38.3
MP-109	MP-114	158	48.0	25	609	18.5	32.9	595	60.2
MP-107	MP-114	140	11.0	25	688	18.5	37.2	254	47.9
MP-106	MP-114	121	14.5	25	796	19.0	41.9	359	72.5
MP-115	MP-114	120	10.0	25	802	19.0	42.2	254	52.6
MP-116	MP-114	78	18.0	25	1234	19.0	64.9	374	63.4
MP-117	MP-114	84	15.0	25	1146	18.0	63.7	274	40.8
MP-118	MP-114	70	14.5	25	1375	16.0	85.9	387	84.1
		<u>109</u>	<u>19.3</u>		<u>878</u>	<u>18.2</u>	<u>48.2</u>		<u>55.3</u>
MP-111	MP-112	390	4.1	137	1352	18.5	73.1	254	128.0
MP-109	MP-112	508	10.6	137	1038	18.5	56.1	254	49.7
MP-101	MP-112	465	46.6	137	1134	18.0	63.0	564	55.7
MP-107	MP-112	420	68.7	137	1256	18.5	67.9	595	42.0
MP-114	MP-112	525	74.2	137	1005	18.5	54.3	548	33.0
MP-118	MP-112	454	14.9	137	1162	16.0	72.6	387	82.1
MP-119	MP-112	234	66.1	137	2254	16.5	136.6	274	9.28
MP-120	MP-112	496	16.7	137	1063	18.0	59.1	374	68.0
		<u>426</u>	<u>25.3</u>		<u>1240</u>	<u>17.8</u>	<u>69.7</u>		<u>47.2</u>
MP-121	MP-122	223	26.1	90	1554	17.5	88.8	254	20.2
MP-120	MP-122	336	17.0	90	1031	18.0	57.3	374	67.1
MP-119	MP-122	343	128.0	90	1010	16.5	61.2	274	4.79
MP-118	MP-122	341	18.7	90	1016	16.0	63.5	387	65.4
MP-123	MP-122	460	117.0	90	753	15.5	48.6	274	5.24
MP-128	MP-122	360	21.9	90	963	17.5	55.0	374	52.2
MP-129	MP-122	480	10.2	90	723	17.0	42.5	254	51.7
MP-130	MP-122	357	20.5	90	971	19.0	51.1	359	51.3
		<u>354</u>	<u>29.5</u>		<u>978</u>	<u>17.1</u>	<u>57.2</u>		<u>27.3</u>

Assumptions: $g = 0.44$ psi/ft
 $\mu = 1$ cp

$\phi = 0.246$
 $c_t = 0.00000875$ psi⁻¹

* $P - P_i$ at $P_D = 1$

** t at $t_D = 1$

TABLE E2
INTERFERENCE TEST RESULTS FOR THE HEGBERG PATTERN

From Well	To Well	Δp_1^* Inches of Water	Δt_1^{**} hr	q bbl/day	$k_e h$ md-ft	h ft	k_e md	r ft	k_ϕ md
MP-218	MP-219	875	13.9	140	616	14.5	42.5	274	44.1
MP-213	MP-219	940	52.0	140	573	11.0	52.1	387	23.5
MP-212	MP-219	799	13.0	140	675	11.5	58.7	274	47.1
MP-211	MP-219	635	24.3	140	849	15.0	56.6	274	46.9
MP-220	MP-219	879	18.2	140	613	16.5	37.2	254	28.9
MP-221	MP-219	772	32.5	140	698	18.0	38.9	359	32.3
MP-222	MP-219	788	14.2	140	684	17.0	38.0	254	37.0
MP-223	MP-219	1070	41.2	140	503	18.0	27.9	374	27.6
		<u>836</u>	<u>23.0</u>		<u>644</u>	<u>15.2</u>	<u>42.8</u>		<u>34.9</u>
MP-208	MP-209	1210	23.0	100	318	15.0	21.2	274	26.6
MP-203	MP-209	690	33.1	100	558	17.0	32.8	374	34.4
MP-202	MP-209	650	15.6	100	592	17.0	34.8	254	33.7
MP-201	MP-209	515	20.6	100	748	18.0	41.6	359	51.1
MP-210	MP-209	265	45.5	100	1453	16.5	88.1	254	11.6
MP-211	MP-209	480	27.0	100	802	14.5	55.3	392	46.5
MP-212	MP-209	684	14.7	100	563	11.5	50.0	274	41.7
MP-213	MP-209	938	80.7	100	410	11.0	37.3	387	15.2
		<u>623</u>	<u>27.8</u>		<u>617</u>	<u>15.1</u>	<u>41.7</u>		<u>29.2</u>
MP-203	MP-207	101	23.7	30	1143	17.0	67.2	374	48.3
MP-204	MP-207	220	53.4	30	525	18.0	29.2	254	9.9
MP-205	MP-207	124	30.3	30	931	21.0	44.3	359	34.7
MP-206	MP-207	153	24.3	30	754	19.0	39.7	254	21.7
MP-215	MP-207	143	33.4	30	808	17.0	47.5	374	34.2
MP-214	MP-207	414	73.7	30	279	15.0	18.6	274	8.3
MP-213	MP-207	210	54.0	30	550	11.0	50.	387	22.7
MP-208	MP-207	196	44.5	30	589	15.0	39.3	274	13.8
		<u>178</u>	<u>39.1</u>		<u>647</u>	<u>16.6</u>	<u>39.6</u>		<u>20.6</u>
MP-216	MP-217	330	21.0	120	1400	18.0	77.8	254	25.1
MP-215	MP-217	690	22.0	120	670	17.0	39.4	374	57.8
MP-214	MP-217	1090	79.5	120	424	15.0	28.3	274	7.7
MP-213	MP-217	854	88.3	120	541	11.0	49.2	387	13.8
MP-218	MP-217	872	39.4	120	530	14.0	37.8	274	15.5
MP-223	MP-217	790	48.0	120	585	18.0	32.5	374	23.7
MP-224	MP-217	370	47.0	120	1249	17.8	70.2	254	11.2
MP-225	MP-217	970	30.5	120	476	21.0	22.7	359	34.5
		<u>692</u>	<u>41.5</u>		<u>668</u>	<u>16.5</u>	<u>41.3</u>		<u>19.4</u>

Assumptions: $g = 0.44 \frac{\text{psi}}{\text{ft}}$ $\phi = 0.246$
 $\mu = 1 \text{ cp}$ $c_t = 0.00000875 \text{ psi}^{-1}$

* $P - P_i$ at $P_D = 1$ ** t at $t_D = 1$

TABLE E3

RESULTS OF PRESSURE BUILDUP TESTS ON PRODUCTION WELLS

<u>Well</u>	<u>Date</u>	<u>q_{final} bbl/day</u>	<u>Q bbl</u>	<u>h ft</u>	<u>kh md-ft</u>	<u>k md</u>	<u>Skin</u>	<u>P_{static} psig</u>	<u>ΔP/q psi/(bbl/day)</u>
MP-112	5/9/75	137	285	17.8	1013	56.9	0.78	170	1.21
MP-114	4/29/75	23.3	117	18.5	-	-	-	182	7.49
MP-122	5/16/75	89.5	197	15.0	728	48.5	1.76	180	1.88
MP-124	4/21/75	149	1221	17.5	897	51.3	-0.79	191	1.20
MP-207	5/29/75	28.8	219	16.5	302	18.3	5.65	202	6.35
MP-209	7/3/75	97.5	214	15.0	587	39.1	-0.44	205	1.94
MP-217	6/9/75	108	250	16.0	532	33.3	-1.32	195	1.69
MP-219	6/23/75	122	285	15.5	551	35.6	-1.29	203	1.57

TABLE E4
FALL-OFF TEST RESULTS FOR INJECTION WELLS

Well	bbl/day	h ft	kh md-ft	k md	Skin	Depth ft	BHP [*] static psig	$\Delta P/q$ psi/(bbl/day)
MP-106	- 78.0	19.0	405	21.2	-2.09	659	176	1.58
MP-108	- 53.3	18.5	468	25.3	1.37	637	160	2.52
MP-110	- 0.63	19.0	-	-	-	626	-	-
MP-116	-125	19.0	833	43.8	-1.11	668	179	1.01
MP-118	-115	16.0	761	47.6	-1.21	651	162	1.17
MP-120	- 72.0	18.0	492	27.3	-0.22	634	153	1.90
MP-126	-123	18.0	1000	55.6	-0.21	675	185	0.97
MP-128	- 99.0	17.3	700	40.5	-0.57	665	173	1.28
MP-130	-120	19.0	716	37.7	-1.24	650	161	1.11
MP-201	- 66.5	18.0	541	30.0	-0.01	668	188	1.81
MP-203	- 70.8	17.0	382	22.7	-1.84	681	182	1.77
MP-205	- 91.2	21.0	494	23.5	-1.53	660	168	1.48
MP-211**	- 85.4	14.5	526	36.3	-2.13	677	197	1.28
MP-213	- 21.8	11.0	248	22.5	2.60	680	193	5.38
MP-215	- 81.8	17.0	380	22.6	-2.34	668	174	1.61
MP-221	- 84.0	18.0	350	19.5	-3.35	726	215	1.34
MP-223	- 36.0	18.0	197	10.1	-1.54	680	190	3.32
MP-225	- 85.2	21.0	337	16.1	-2.98	724	206	1.47

* Static bottom-hole pressure

** Data taken before the twin well (MP-226) was drilled

TABLE E5
INJECTION WELLS--BEFORE AND AFTER CLEANOUT

Date	Well MP-126		Well MP-128		Well MP-130		Well MP-203		Well MP-213	
	7/31/75	8/26/75	8/1/75	8/27/75	8/2/75	8/29/75	8/5/75	8/28/75	7/21/75	8/30/75
** q _{final} , bbl/day	-120	-123	-108	-99	-70	-120	-69.8	-70.8	-8.11	-21.8
Q, bbl	45.6	46.9	41.2	40.0	27.8	46.6	28.6	28.9	27.8	14.3
h, ft	18.0	18.0	17.3	17.3	19.0	19.0	17.0	17.0	11.0	11.0
kh, md-ft	1000	1000	717	700	615	716	382	386	440*	248
k, md	55.6	55.6	41.4	40.5	32.4	37.7	22.5	22.7	40.0	22.5
S, dimensionless	0.03	-0.21	-0.86	-0.57	1.53	-1.24	-1.76	-1.84	39.7	2.60
Depth, ft	674	675	665	665	644	650	677	681	680	680
BHP _{static} , psig	185	185	173	173	159	161	182	182	181	193
$\Delta P/q$, psi/(bbl/day)	1.00	0.97	1.19	1.28	1.93	1.11	1.80	1.77	15.2	5.38

* Assumed value from interference tests.

** Negative rate values denote injection.

FIGURE E-1
DIRECTIONAL PERMEABILITY ON 3.2 ACRE SPACING
CHESNEY PATTERN

HEGBERG PATTERN

LEGEND

- INJECTION WELLS ○
- PRODUCTION WELLS ●
- MONITORING WELLS ▲
- δ = PERMEABILITY CONTRAST

FIGURE E-2

DIRECTIONAL PERMEABILITY ON 6.4 ACRE SPACING

LEGEND

- INJECTION WELLS ○
- PRODUCTION WELLS ●
- MONITORING WELLS ▲
- δ = PERMEABILITY CONTRAST

APPENDIX F
PERFORMANCE PREDICTION

Tables and Figures

TABLE F1
REVISED VOLUMETRIC ESTIMATES OF OIL IN PLACE,
PORE VOLUME, AND OIL SATURATION

<u>Revised Volumetric Estimate</u>	<u>Confined Chesney Pattern</u>	<u>Confined Hegberg Pattern</u>	<u>Chesney and Hegberg Patterns</u>
Oil presently in place, reservoir bbl	303,200	261,200	564,400
Pore volume, reservoir bbl	910,000	849,500	1,759,500
Oil saturation, percent	33.3	30.7	32.1

TABLE F2
RESERVOIR DATA FOR EACH ZONE BY WELLS

Well No.	Upper Zone				Lower Zone			
	[*] h ft	k md	ϕ percent	S_o percent	h ft	k md	ϕ percent	S_o percent
MP-101	12.	199.2	24.7	36.9	6.5	278.8	25.2	35.7
MP-103	14.5	100.1	25.0	11.9	4.	395.0	23.6	37.1
MP-104	15.	290.6	24.7	34.3	4.	239.8	22.9	29.6
MP-106	14.5	415.7	24.9	36.3	4.	14.1	23.6	29.9
MP-110	13.	302.9	23.6	31.9	7.5	495.2	23.7	40.9
MP-112	10.5	N.A.**	25.5	29.3	10.	N.A.	24.4	29.3
MP-116	14.5	259.1	25.8	38.0	4.5	346.9	23.2	31.6
MP-120	12.5	179.2	23.3	37.5	6.	65.7	25.6	44.9
MP-122	8.	416.0	25.8	36.5	7.	380.1	22.5	27.8
MP-126	17.	N.A.	24.3	33.2	2.5	N.A.	N.A.	N.A.
MP-128	14.	N.A.	27.2	45.1	6.5	N.A.	23.9	38.1
MP-130	14.	180.8	24.5	26.5	5.5	272.8	24.2	23.7
MP-201	14.5	63.0	23.6	32.2	6.	232.6	N.A.	N.A.
MP-203	13.	323.2	25.0	35.4	5.	333.0	25.0	39.1
MP-205	13.5	291.0	22.8	30.0	7.	29.5	24.4	31.2
MP-211	14.5	N.A.	25.2	29.2	5.	N.A.	20.8	18.7
MP-213	6.5	182.6	25.9	32.5	4.	464.5	26.7	31.9
MP-215	8.5	320.5	23.3	27.9	8.	175.1	25.8	33.6
MP-221	14.	304.	25.3	36.0	4.	345.3	22.1	24.9
MP-223	6.5	222.3	19.0	15.2	10.5	171.4	23.0	30.9
MP-225	11.	21.6	22.8	31.1	9.5	85.7	22.1	22.8

* h = thickness, k = average air permeability, ϕ = average porosity, S_o = average oil saturation

** N.A. = Data not available.

TABLE F3
 AVERAGE THICKNESS AND THICKNESS-WEIGHTED POROSITY AND PERMEABILITY
 BY LEASE (PATTERN) AND BY ZONE

	<u>Average Thickness feet</u>	<u>Average Porosity fraction</u>	<u>Average Permeability millidarcies</u>
Chesney, Upper Zone	13.5	0.249	254
Chesney, Lower Zone	6.0	0.240	291
Chesney, Total	19.5	0.246	265
Hegberg, Upper Zone	11.3	0.239	216
Hegberg, Lower Zone	6.6	0.237	195
Hegberg, Total	17.9	0.238	208
Total Project*, Upper Zone	12.6	0.245	238
Total Project*, Lower Zone	6.2	0.238	240
Total Project*, Total	18.8	0.243	239

* Confined Chesney and Hegberg Patterns

TABLE F4
 MEAN PERMEABILITY AND DYKSTRA-PARSONS PERMEABILITY
 VARIANCE COEFFICIENT BY LEASE (PATTERN) AND BY ZONE

<u>Sample</u>	<u>Number of Data Points</u>	<u>Percent of Data Below 100 md</u>	<u>Data Above 100 md</u>		<u>All Data</u>	
			<u>Mean Permeability millidarcies</u>	<u>Dykstra- Parsons Coefficient</u>	<u>Mean Permeability millidarcies</u>	<u>Dykstra- Parsons Coefficient</u>
Chesney Upper Zone	135	21	396	0.45	226	0.71
Chesney Lower Zone	60	22	535	0.45	208	0.85
Hegberg Upper Zone	93	26	379	0.49	140	0.85
Hegberg Lower Zone	57	33	494	0.50	149	0.86

TABLE F5
ESTIMATED INJECTION RATES FOR WELL MP-213
130 DAYS AFTER START OF INJECTION

<u>Effective Well Radius feet</u>	<u>Injection Pressure psia</u>	<u>Twinned</u>	<u>Well Rate bbl/day</u>
0.33	400	No	57
0.75	400	No	63
1.50	400	No	71
3.00	400	No	80
0.33	500	No	90
0.75	500	No	100
1.50	500	No	112
3.00	500	No	126
0.33	400	Yes	81
1.00	400	Yes	90
3.00	400	Yes	102
0.33	500	Yes	127
1.00	500	Yes	142
3.00	500	Yes	160

TABLE F6
COMPUTED AVERAGE RATES FOR CHESNEY INJECTION WELLS
(Rates in Barrels per Day)

Time In Days	Well MP-118	Wells MP-106 and MP-110	Wells MP-126 and MP-130	Well MP-108	Wells MP-116 and MP-120	Well MP-128	Wells MP-112 and MP-114	Wells MP-122 and MP-124	Total Chesney Injection	Total Chesney Production
0	-186*	-170	-161	-174	-173	-164	192	195	-1533	775
1	-172	-157	-142	-161	-158	-146	206	211	-1394	834
2	-165	-149	-133	-154	-150	-137	212	219	-1322	863
3	-162	-144	-128	-150	-146	-133	216	223	-1279	879
4	-160	-141	-124	-147	-143	-130	219	226	-1252	889
5	-157	-137	-121	-143	-139	-128	222	228	-1221	900
7	-155	-133	-117	-140	-136	-126	224	230	-1193	909
10	-154	-129	-115	-138	-133	-124	226	232	-1170	917
14	-152	-126	-112	-135	-131	-123	229	234	-1147	924
20	-151	-122	-110	-132	-128	-121	231	235	-1123	932
30	-150	-118	-108	-129	-126	-120	233	237	-1103	938
45	-148	-115	-106	-127	-123	-119	235	238	-1081	945
75	-147	-111	-104	-124	-121	-118	237	239	-1061	952
130	-146	-109	-102	-122	-119	-117	238	240	-1045	957
210	-145	-106	-101	-120	-118	-116	240	241	-1030	961
365	-144	-104	-100	-118	-116	-115	241	242	-1017	966
730	-143	-102	-99	-117	-116	-115	242	242	-1009	968
1460	-143	-101	-98	-116	-115	-115	242	243	-1002	970
3650										

* Negative values denote injection and positive values denote production.

TABLE F7

ADJUSTED RELATIVE RATES

(As Percent of the Rate of Well MP-118)

Time In Days	Well MP-118	Wells MP-106 and MP-110	Wells MP-126 and MP-130	Well MP-108	Wells MP-116 and MP-120	Well MP-128	Wells MP-112 and MP-114	Wells MP-122 and MP-124	Total Chesney Injection	Total Chesney Production
0	100	91.0	86.3	93.3	93.0	88.2	103.2	104.6	822	416
1	100	91.0	82.7	93.3	92.0	84.5	119.4	122.6	809	484
2	100	90.2	80.4	93.0	90.9	82.8	128.4	132.3	799	522
3	100	89.3	78.9	92.4	90.0	82.0	133.8	137.9	791	543
4	100	88.4	77.9	91.9	89.3	81.5	137.2	141.4	785	557
5	100	86.9	76.6	91.1	88.4	81.1	140.9	145.0	776	572
7	100	85.4	75.5	90.2	87.4	80.9	144.3	148.1	768	585
10	100	83.9	74.6	89.4	86.5	80.7	147.2	150.8	760	596
14	100	82.4	73.7	88.5	85.7	80.5	150.0	153.3	753	607
20	100	80.7	72.8	87.5	84.8	80.4	152.9	155.9	745	618
30	100	79.2	72.1	86.5	84.0	80.3	155.6	158.2	737	628
45	100	77.5	71.3	85.4	83.2	80.2	158.4	160.6	730	638
75	100	75.8	70.6	84.3	82.4	80.2	161.0	162.9	722	648
130	100	74.4	70.1	83.4	81.8	80.1	163.2	164.7	716	656
210	100	73.1	69.6	82.5	81.2	80.1	165.2	166.3	711	663
365	100	71.9	69.2	81.7	80.7	80.1	167.0	167.8	705	670
730	100	71.1	68.9	81.2	80.4	80.1	168.1	168.8	702	674
1460	100	70.4	68.7	80.8	80.1	80.1	169.1	169.6	699	677
3650										

TABLE F8

INDIVIDUAL WELL RATES AS PERCENT OF THE TOTAL CHESNEY INJECTION RATE

<u>Time In Days</u>	<u>Well MP-118</u>	<u>Wells MP-106 and MP-110</u>	<u>Wells MP-126 and MP-130</u>	<u>Well MP-108</u>	<u>Wells MP-116 and MP-120</u>	<u>Well MP-128</u>	<u>Wells MP-112 and MP-114</u>	<u>Wells MP-122 and MP-124</u>	<u>Total Chesney Injection</u>	<u>Total Chesney Production</u>
0	12.2	11.1	10.5	11.3	11.3	10.7	12.5	12.7	100	50.6
1	12.4	11.2	10.2	11.5	11.4	10.4	14.8	15.1	100	59.8
2	12.5	11.3	10.1	11.6	11.4	10.4	16.1	16.6	100	65.3
3	12.6	11.3	10.0	11.7	11.4	10.4	16.9	17.4	100	68.7
4	12.7	11.3	9.9	11.7	11.4	10.4	17.5	18.0	100	71.0
5	12.9	11.2	9.9	11.7	11.4	10.5	18.2	18.7	100	73.7
7	13.0	11.1	9.8	11.8	11.4	10.5	18.8	19.3	100	76.2
10	13.1	11.0	9.8	11.8	11.4	10.6	19.4	19.8	100	78.4
14	13.3	10.9	9.8	11.8	11.4	10.7	19.9	20.4	100	80.6
20	13.4	10.8	9.8	11.7	11.4	10.8	20.5	20.9	100	82.9
30	13.6	10.7	9.8	11.7	11.4	10.9	21.1	21.4	100	85.1
45	13.7	10.6	9.8	11.7	11.4	11.0	21.7	22.0	100	87.4
75	13.8	10.5	9.8	11.7	11.4	11.1	22.3	22.5	100	89.7
130	14.0	10.4	9.8	11.6	11.4	11.2	22.8	23.0	100	91.5
210	14.1	10.3	9.8	11.6	11.4	11.3	23.2	23.4	100	93.3
365	14.2	10.2	9.8	11.6	11.4	11.3	23.7	23.8	100	94.9
730	14.2	10.1	9.8	11.6	11.4	11.4	23.9	24.0	100	96.0
1460	14.3	10.1	9.8	11.5	11.5	11.4	24.2	24.2	100	96.8
3650										

TABLE F9
REVISED OIL RECOVERY SCHEDULE
FOR HEGBERG PATTERN

<u>Date</u>	<u>Production Rate</u> [*] <u>bbbl/day</u>		<u>Water-</u> <u>Oil</u> <u>Ratio</u>	<u>Cumulative Production</u> [*] <u>barrels x 10⁻³</u>		<u>Cumulative</u> <u>Injection</u> <u>bbbl x 10⁻³</u>	<u>Cumulative</u> <u>Water-Oil</u> <u>Ratio</u>
	<u>Oil</u>	<u>Water</u>		<u>Oil</u>	<u>Water</u>		
12-31-76	0	800	Infinite	0	24.3	24.3	Infinite
12-31-77	35	765	22.2	1.37	315	316	229
12-31-78	297	503	1.7	81.2	527	608	6
12-31-79	190	610	3.2	176	724	900	4
12-31-80	109	691	6.3	226	966	1,192	4
12-31-81	76	724	9.5	259	1,224	1,484	5
12-31-82	58	742	12.9	283	1,492	1,775	5

* These projected production schedules correspond to an optimistic case and may be considered the upper bounds for expected recovery. The assumptions used in making these calculations are given in the section on "Performance Prediction."

TABLE F10
REVISED OIL RECOVERY SCHEDULE
FOR CHESNEY PATTERN

<u>Date</u>	<u>Production Rate</u> [*] <u>bb1/day</u>		<u>Water-</u> <u>Oil</u> <u>Ratio</u>	<u>Cumulative Production</u> [*] <u>barrels x 10⁻³</u>		<u>Cumulative</u> <u>Injection</u> <u>bb1 x 10⁻³</u>	<u>Cumulative</u> <u>Water-Oil</u> <u>Ratio</u>
	<u>Oil</u>	<u>Water</u>		<u>Oil</u>	<u>Water</u>		
12-31-77	0	900	Infinite	0	164	164	Infinite
12-31-78	267	633	2.4	37.5	455	492	12
12-31-79	283	617	2.2	154	667	821	4
12-31-80	145	755	5.2	226	923	1,149	4
12-31-81	96	804	8.4	268	1,210	1,477	5
12-31-82	70	830	11.9	297	1,509	1,806	5

* These projected production schedules correspond to an optimistic case and may be considered the upper bounds for expected recovery. The assumptions used in making these calculations are given in the section on "Performance Prediction."

TABLE F11
MONITORING WELL BOTTOM-HOLE PRESSURE CALCULATION

	<u>Data</u>	
	<u>Chesney Pattern</u>	<u>Hegberg Pattern</u>
Permeability, md	48.8	27.4
Thickness, ft	18	18
Permeability-thickness, md-ft	878	493
Porosity, fraction	0.241	0.241
Viscosity, cp	1.07	1.07
Formation volume factor, bbl/stb	1	1
Total compressibility, psi^{-1}	7.4×10^{-6}	7.4×10^{-6}
Initial pressure, psig	190	190
Production well pressure, psig	30	30
Injection well pressure, psig	500	500
Wellbore radius, ft	0.3333	0.3333
Production well skin factor	1	-1
Injection well skin factor	55	13

Results for December 3, 1975

	<u>Calculated</u>	<u>Observed</u>
Average production rate, bbl/day/well	100.	99.
Average injection rate, bbl/day/well	31.	32.

Pressure Change from Initial Pressure, psi

<u>Well</u>	<u>Calculated</u>	<u>Observed</u>
MP-101	-16	-7
MP-104	4	1
MP-109	-26	-19
MP-115	-24	0
MP-127	-14	-24
MP-216	10	1
MP-220	10	17
MP-224	11	10

TABLE F12
COMPARISON OF $k_w h$ FOR INJECTION WELLS

Well No.	$k_w h$ (a) md-ft	kh (b) md-ft	k_{rw}	$k_w h$ (c) md-ft
MP-106	405	6084	0.0666	-
MP-108	468	-	-	311
MP-110	-	7652	-	1243(d)
MP-116	833	5318	0.1566	-
MP-118	761	-	-	-
MP-120	492	2634	0.1868	-
MP-126	1000	-	-	-
MP-128	700	-	-	-
MP-130	716	4032	0.1776	-
MP-201	541	2309	0.2343	194
MP-203	382	5867	0.0651	-
MP-205	494	4135	0.1195	-
MP-211	526	-	-	865
MP-213	248	3045	0.0814	-
MP-215	380	4125	0.0921	-
MP-221	350	5637	0.0621	557
MP-223	197	3245	0.0607	-
MP-225	337	1052	0.3204	-
Ave.			0.1353	-

- (a) From interference data discussed in section "Pattern Pressure Transient Tests."
- (b) Summation of kh from upper and lower zones shown in Table F2.
- (c) From Muskat plots.
- (d) A value of 1035 was estimated from kh using the average k_{rw} from column 4.

TABLE F13
INJECTION WELL SKIN FACTORS

Well No.	From Pressure Survey of Dec. 4, 1975	Hall Plot for Dec. 4, 1975	From Pressure Survey Before Injection	Hall Plot for First Week	Hall Plot for April 2, 1976
MP-106	29.	30.	-2.1	-3.3	7.4
MP-108	28.	23.	-1.7	-	3.5
MP-110	-1.4	5.0	-2.9	0.7	3.1
MP-116	107.	67.	-1.1	-	17.
MP-118	64.	45.	-1.2	-1.8	6.5
MP-120	36.	23.	-0.2	-	0.1
MP-126	113.	78.	-0.2	-	24.
MP-128	65.	57.	-0.6	-	3.0
MP-130	65.	57.	-1.2	-2.0	9.2
MP-201	3.2	1.4	0.0	-	9.0
MP-203	36.	31.	-1.8	-	3.4
MP-205	18.	11.	-1.5	-	4.0
MP-211	22.	16.	-2.1	-	14.
MP-213	-1.8	-2.2	0.0	-	1.7
MP-215	28.	19.	-2.3	-	-0.6
MP-221	2.1	1.1	-3.4	-	-1.7
MP-223	-4.1	-3.6	-3.3	-	-2.3
MP-225	9.5	3.1	-3.0	-	0.3

FIGURE F-1
WELL LOCATIONS AND RELATIVE WELL RATES FOR
RELATIVE RATE STUDY--CASE I

Negative values denote injection, and positive values denote production.

FIGURE F-2
WELL LOCATIONS AND RELATIVE WELL RATES FOR
RELATIVE RATE STUDY--CASE II

Negative values denote injection, and positive values denote production.

FIGURE F-3
WELL LOCATIONS AND RELATIVE WELL RATES FOR
RELATIVE RATE STUDY--CASE III

Negative values denote injection, and positive values denote production.

FIGURE F-4
WELL LOCATIONS AND RELATIVE WELL RATES
FOR RELATIVE RATE STUDY--CASE IV

Negative values denote injection, and positive values denote production.

FIGURE F-5
WELL LOCATIONS AND RELATIVE WELL RATES
FOR RELATIVE RATE STUDY--CASE V

Negative values denote injection, and positive values denote production.

FIGURE F-6
WELL LOCATIONS AND RELATIVE WELL RATES
FOR RELATIVE RATE STUDY--CASE VI

Negative values denote injection, and positive values denote production.

FIGURE F-7
FLOOD FRONTS AND STREAMLINES FOR
RELATIVE RATE STUDY--CASE I

FIGURE F-8
FLOOD FRONTS AND STREAMLINES FOR
RELATIVE RATE STUDY--CASE II

FIGURE F-9
FLOOD FRONTS AND STREAMLINES FOR
RELATIVE RATE STUDY--CASE III

FIGURE F-10
FLOOD FRONTS AND STREAMLINES FOR
RELATIVE RATE STUDY--CASE IV

FIGURE F-11
FLOOD FRONTS AND STREAMLINES FOR
RELATIVE RATE STUDY--CASE V

FIGURE F-12
FLOOD FRONTS AND STREAMLINES FOR
RELATIVE RATE STUDY--CASE VI

FIGURE F-13

COMPARISON OF INJECTED FLUID
CUTS FOR CASES I, II, AND III
OF RELATIVE RATE STUDY

FIGURE F-14

II-85

COMPARISON OF INJECTED FLUID
CUTS FOR CASES I AND IV
OF RELATIVE RATE STUDY

COMPARISON OF INJECTED FLUID
CUTS FOR CASES I AND V
OF RELATIVE RATE STUDY

COMPARISON OF INJECTED FLUID
CUTS FOR CASES I AND VI
OF RELATIVE RATE STUDY

FIGURE F-17
TOTAL RELATIVE MOBILITY FROM
RELATIVE PERMEABILITY DATA
(CHESNEY MP-124, SAMPLE NO. 2)

FIGURE F-18
DATA BASE SYSTEM

ENGINEERING AND OPERATIONS--TABLES AND FIGURES

TABLE GI
EL DORADO MICELLAR-POLYMER PROJECT WELL STIMULATION SUMMARY

(January, 1975-May, 1976)

Well	Date	Workover Description	Before Work		After Work		One Month After		Remarks
			Rate bbl/day	Wellhead Pressure psig	Rate bbl/day	Wellhead Pressure psig	Rate bbl/day	Wellhead Pressure psig	
MP-106	2/26/76	Swabbed and bailed three hr							
	2/27/76	Acidized with 1500 gal (All 1500 gal acid treatments are described in detail in the text.)	20	200	149	160	55	190	Four stage treatment
MP-108	11/7/75	Acidized with 300 gal HCl followed by 120 gal Chesney brine							
	3/2/76	Swabbed and bailed four hr							
	3/3/76	Acidized with 1500 gal	27	180	151	150	102	185	Four stage treatment
MP-110	8/18/75	Underreamed hole to 7 1/2 inches from 614 feet to 625 feet							Work performed prior to pretreatment injection
	8/19/75	Jet acidized with 500 gal 15 percent HCl and 1500 lb surfactant							
	9/17/75	Perforated 611-621 feet with four shots/ft							
	11/10/75	Shot with three solid charges in three places: 617-618 ft, 620-621 ft, and 623-624 ft							
	3/9/76	Swabbed and bailed four hr							
	3/10/76	Acidized with 1500 gal	63	195	165	60	158	80	Four stage treatment
MP-112, Producer		No work to date							
MP-114, Producer	6/14/75	Acidized with 500 gal HCl, 1000 gal HF, and 250 gal HCl	1 oil 23 water		1 oil 23 water				Surface pressure held below 180 psig during treatment
	6/15/75	Swabbed for eight hr							
	6/16/75	Swabbed for eight hr							
	6/17/75	Swabbed for eight hr							Swabbed total of 65.3 bbl in 24 hr
	6/28/75	Treated with 750 gal xylene, flushed with 100 gal diesel fuel	1 oil 27 water						Surface pressure held below 180 psig during treatment
	9/24/75	Treated with 400 gal EDTA, with 1000 gal El Dorado city drinking water	1 oil 23 water		trace oil 60 water			1 oil 23 water	
	11/11/75	Fractured with 500 lb 20-40 sand 25 lb MG-6 (gel agent), 12.5 lb CW 1 (gel breaker) in 1000 gal salt water	1 oil 27 water		trace oil 114 water			5 oil 46 water	Formation broke down at 520 psig wellhead pressure
MP-116	2/20/76	Swabbed for four hr							
	2/20/76	Acidized with 1500 gal	27	185	165	140	66	185	Four stage treatment
	4/7/76	Acidized with 3400 gal: 850 gal HCl, 1700 gal HF, 850 gal HCl	37	185	152	90			Three stage treatment; no xylene
MP-118	12/23/76	Attempted to acidize with 100 gal xylene and 1500 gal 15 percent HCl			47	200	25	200	Injection stopped after 6 hr; injected only 100 gal HCl
	3/12/76	Acidized with 1500 gal	12	185	138	185	52	185	Four stage treatment
MP-120	12/10/75	Swabbed for seven hr							
	12/11/75	Swabbed for four hr							
	12/23/75	Acidized with 100 gal xylene, 750 gal 28 percent HCl	65	200	90	210	114	225	
	3/10/76	Swabbed for four hr							
	3/11/76	Acidized with 1500 gal	78	190	146	170	135	190	Four stage treatment
MP-122, Producer		No work to date							
MP-124, Producer		No work to date							

TABLE G1
EL DORADO MICELLAR-POLYMER PROJECT WELL STIMULATION SUMMARY
(continued)

Well	Date	Workover Description	Before Work		After Work		One Month After		Remarks
			Rate bbl/day	Wellhead Pressure psig	Rate bbl/day	Wellhead Pressure psig	Rate bbl/day	Wellhead Pressure psig	
MP-126		No work to date							
MP-128	3/3/76	Swabbed and bailed three hr							
	3/9/76	Acidized with 1500 gal	97	190	137	130	130	190	Four stage treatment
MP-130	2/27/76	Swabbed for three hr							
	3/1/76	Treated with 41 bbl fresh water and 10 bbl surfactant	14	200	2	190			Injected only two bbl surfactant
	3/3/76	Swabbed for four hr							Shut down to wait on acid treatment
	3/4/76	Acidized with 1500 gal	2	190	154	115	92	190	Four stage treatment
MP-201	4/14/76	Acidized in three stages with 850 gal HCl, 1700 gal HF, and 850 gal HCl	32	205	153	165			
MP-203	12/24/76	Treated with 150 gal, 25 percent HCl, 32 lb citric, and 7 1/2 gal acetic acid	14	210	45	200	25	220	
	2/24/76	Swabbed for three hr							
	2/25/76	Acidized with 1500 gal	82	190	168	160	81	195	Four stage treatment
	4/15/76	Treated in three stages with 850 gal HCl, 1700 gal HF, and 850 gal HCl	70	195	131	200			
MP-205	2/21/76	Acidized with 1500 gal	16	195	161	165	70	200	Four stage treatment
MP-207, Producer	11/5/75	Treated with 2.5 gal detergent in 12 bbl fresh water, 250 gal 15 percent FE Acid, followed by 2.5 gal detergent with 10 bbl fresh water							
	11/11/75	Fracture with 500 lb 20-40 sand in 1000 gal salt water			2 oil 85 water		3 oil 72 water		Formation broke down at 900 psig wellhead pressure
MP-209, Producer		No work to date							
MP-211	4/13/76	Acidized in three stages with 850 gal HCl, 1700 gal HF, 850 gal HCl	2	180	119	200			
MP-213*	8/27/75	Acidized with 500 gal mud acid with inhibitor							
	9/17/75	Perforated 673-679 ft four shots/ft							
	11/26/75	Shot with three lb solid charges in two places: 674-675 ft and 678-679 ft							
	3/12/76	Swabbed for four hr							
	3/13/76	Acidized with 1500 gal	33	210	85	200	77	200	Four stage treatment
MP-215	2/28/76	Swabbed for five hr							
	3/4/76	Acidized with 1500 gal	32	200	151	80	126	195	Four stage treatment
MP-217, Producer		No work to date							
MP-219, Producer		No work to date							
MP-221	7/3/74	Swabbed for ten hr							
	7/24/74	Treated with 100 gal 15 percent HCl and 500 lb boric acid with 105 bbl fresh water							
	3/3/76	Swabbed for four hr							
	3/5/76	Acidized with 1500 gal	62	200	151	55	150	190	Four stage treatment
MP-223	11/7/75	Acidized with 300 gal mud acid							
	11/8/75	Swabbed 15 bbl							

*The rates and pressures also include twin well MP-226.

TABLE G1
EL DORADO MICELLAR-POLYMER PROJECT WELL STIMULATION SUMMARY
(continued)

<u>Well</u>	<u>Date</u>	<u>Workover Description</u>	<u>Before Work</u>		<u>After Work</u>		<u>One Month After</u>		<u>Remarks</u>
			<u>Rate</u> <u>bbl/day</u>	<u>Wellhead</u> <u>Pressure</u> <u>psig</u>	<u>Rate</u> <u>bbl/day</u>	<u>Wellhead</u> <u>Pressure</u> <u>psig</u>	<u>Rate</u> <u>bbl/day</u>	<u>Wellhead</u> <u>Pressure</u> <u>psig</u>	
MP-223	11/25/75	Shot with three lb charges in three places: 671-672 ft, 674-675 ft, and 677-678 ft							
	3/5/76	Swabbed for three hr							
	3/6/76	Acidized with 1500 gal	40	200	146	185	91	195	Four stage treatment
MP-225	7/25/74	Treated with 100 gal 15 percent HCl and 500 lb borax solution with 150 bbl fresh water							
	3/4/76	Swabbed for three hr							
	3/6/76	Acidized with 1500 gal	35	215	150	195	97	210	Four stage treatment
MP-226**	11/25/76	Shot with three lb solid charges in three places: 675-676 ft, 678-679 ft, and 681-682 ft							
	3/14/76	Acidized with 1500 gal	35	210	85	200	77	200	Four stage treatment

**The rates and pressures also include well MP-213.

TABLE G2
EL DORADO DEMONSTRATION PROJECT
MONTHLY PRODUCTION DATA

Well Number	November, 1975		December, 1975		January, 1976		February, 1976		March, 1976		April, 1976		May, 1976	
	Oil bbl	Water bbl	Oil bbl	Water bbl	Oil bbl	Water bbl	Oil bbl	Water bbl	Oil bbl	Water bbl	Oil bbl	Water bbl	Oil bbl	Water bbl
MP-112	6	980	17	2650	11	4030	34	3782	37	3451	36	5075	8	5700
MP-114	19	331	53	899	26	943	45	1392	76	1798	72	2320	44	1800
MP-122	6	648	13	1752	12	2511	23	2325	50	2581	61	4205	27	4200
MP-124	3	1207	9	3263	23	4960	57	4805	64	4379	24	7337	8	8120
MP-207	26	486	70	1314	35	1767	103	1537	37	1914	61	2204	88	2400
MP-209	3	851	9	2299	5	3317	34	3038	51	3016	48	4408	9	2850
MP-217	6	883	18	2387	12	3751	23	3630	38	3712	24	4698	44	4500
MP-219	6	988	18	2672	18	4371	23	3162	38	3364	49	4321	9	4350

TABLE G3

RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
CHESNEY PATTERN

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	1	4	8	23	55	0	0	1094	822	873	917	619	19	4325	4325
11.23	75	137	177	171	173	173	173	833	776	632	494	414	352	326	155	3827	8152
11.30	177	177	178	180	178	177	178	340	333	287	257	322	399	408	178	2346	10498
12.07	177	156	148	151	151	168	179	426	464	392	377	383	432	460	162	2934	13432
12.14	179	181	181	181	183	182	182	430	417	447	326	372	395	371	182	2758	16190
12.21	182	182	181	186	186	186	186	394	378	382	445	446	444	433	185	2922	19112
12.28	186	186	180	162	168	191	191	426	419	444	416	405	478	479	181	3067	22179
1.04	191	191	191	195	196	149	149	475	467	426	380	329	320	327	181	2724	24903
1.11	149	149	149	147	192	193	193	345	313	320	307	394	356	364	168	2399	27302
1.18	192	192	192	190	191	195	195	377	386	371	323	395	411	402	193	2665	29967
1.25	195	194	195	173	157	157	157	403	412	433	364	279	295	296	176	2482	32449
2.01	157	147	156	157	157	157	157	250	275	266	243	275	342	346	156	1997	34446
2.08	153	153	153	153	153	155	155	307	278	310	308	306	284	297	154	2090	36536
2.15	155	156	156	155	143	142	146	295	296	302	288	303	298	393	151	2175	38711
2.22	140	141	142	140	140	131	140	435	447	435	410	431	559	534	140	3251	41962
2.29	141	140	122	115	133	129	135	459	461	371	496	721	761	737	131	4006	45968
3.07	132	132	146	144	176	167	168	765	728	818	909	897	1052	1105	153	6274	52242
3.14	177	176	177	178	178	168	178	1053	986	904	957	974	967	937	177	6778	59020
3.21	176	175	165	175	173	178	175	961	909	374	751	1016	953	912	174	5876	64896
3.28	156	157	157	157	154	153	155	811	810	803	764	762	784	817	156	5551	70447
4.04	155	157	157	148	145	147	164	822	830	787	799	822	802	855	154	5717	76164
4.11	163	167	169	169	171	171	170	851	952	872	876	861	862	843	169	6117	82281
4.18	169	170	169	170	168	170	171	822	803	807	693	778	766	823	170	5492	87773
4.25	173	172	172	175	170	172	176	827	786	797	777	767	814	811	173	5579	93352
5.02	172	175	174	178	174	175	174	791	769	726	685	653	658	613	175	4895	98247
5.09	182	173	176	176	182	185	183	679	652	679	645	651	643	628	180	4577	102824
5.16	183	182	182	183	172	142	159	607	594	619	617	635	710	815	172	4597	107421
5.23	157	162	166	162	155	134	166	885	894	945	1054	1088	1150	1293	158	7309	114730
5.30	169	166	167	170	168	170	172	1331	1250	1236	1186	1192	1221	1142	169	8558	123288

TABLE G4
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
HEGGERG PATTERN

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	28	37	67	81	102	0	0	1034	827	876	852	579	64	4168	4168
11.23	128	126	128	133	137	140	155	816	648	520	435	421	424	507	136	3771	7939
11.30	156	173	177	165	168	176	176	534	620	568	643	631	657	542	171	4195	12134
12.07	176	176	187	180	161	171	193	525	472	492	529	454	440	514	178	3426	15560
12.14	197	195	191	206	202	205	204	502	516	517	368	509	506	460	200	3378	18938
12.21	202	203	202	205	202	203	203	482	458	476	468	517	512	482	203	3395	22333
12.28	203	203	203	202	200	203	203	469	438	449	448	475	498	493	203	3270	25603
1.04	202	202	202	198	204	204	203	503	501	459	398	442	456	442	203	3201	28804
1.11	203	203	203	199	200	198	200	465	389	394	398	411	424	417	201	2898	31702
1.18	201	200	197	197	203	203	203	309	406	406	407	402	395	381	201	2706	34408
1.25	202	202	203	163	141	141	141	392	427	431	308	155	186	181	171	2080	36488
2.01	116	118	118	119	119	119	118	171	178	175	159	154	153	158	119	1148	37636
2.08	117	118	116	117	117	117	117	157	172	162	167	165	160	149	117	1132	38768
2.15	118	117	117	117	113	109	112	169	186	195	193	183	174	153	115	1253	40021
2.22	115	117	93	113	105	108	111	328	351	299	380	425	421	452	109	2656	42677
2.29	87	87	88	88	64	42	123	402	398	397	366	438	292	674	83	2967	45644
3.07	122	141	147	186	185	191	198	945	1025	1053	1134	1057	964	1087	168	7265	52909
3.14	198	195	196	188	171	192	200	988	941	981	901	773	832	828	192	6244	59153
3.21	198	198	198	199	196	196	195	909	784	398	965	988	816	837	198	5697	64850
3.28	175	176	176	175	174	173	176	774	762	760	726	745	742	748	175	5257	70107
4.04	176	175	175	176	176	178	195	752	764	742	728	722	694	690	179	5092	75199
4.11	187	177	197	200	196	196	197	636	707	685	766	876	927	927	193	5524	80723
4.18	196	196	196	193	196	200	195	939	937	859	873	844	939	929	196	6320	87043
4.25	195	195	195	198	198	197	185	878	895	931	913	919	995	955	195	6486	93529
5.02	195	195	195	197	193	198	198	989	882	877	861	816	857	861	196	6143	99672
5.09	197	194	195	194	188	170	169	840	814	753	806	763	688	666	187	5330	105002
5.16	169	175	175	172	175	185	176	690	683	704	685	689	743	692	176	4886	109888
5.23	171	175	174	193	175	172	160	673	642	650	640	651	493	463	175	4212	114100
5.30	146	149	149	150	128	171	206	559	620	601	607	620	773	732	157	4512	118612

TABLE G5
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-106

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	10	15	35	70	0	0	105	88	96	94	65	26	448	448
11.23	105	160	200	200	200	200	200	89	69	45	34	28	25	25	181	315	763
11.30	200	200	200	200	200	200	200	30	27	23	18	25	34	28	200	185	948
12.07	200	200	195	200	200	195	200	27	33	30	25	26	31	36	199	208	1156
12.14	200	200	200	200	205	205	205	37	37	38	19	24	28	25	202	208	1364
12.21	200	200	200	205	205	205	205	29	25	17	15	19	20	19	203	144	1508
12.28	205	205	200	170	185	210	210	20	20	46	42	25	35	39	198	227	1735
1.04	210	210	210	210	210	210	210	40	39	26	19	15	20	20	210	179	1914
1.11	210	210	210	210	210	210	210	20	20	20	20	43	18	20	210	161	2075
1.18	210	210	210	210	210	210	210	21	24	24	21	23	19	17	210	149	2224
1.25	210	210	210	210	210	210	210	20	23	27	26	25	31	28	210	180	2404
2.01	210	210	210	210	210	210	210	23	24	24	19	19	27	32	210	168	2572
2.08	210	210	210	210	210	210	210	30	20	20	20	15	20	20	210	145	2717
2.15	210	210	210	210	185	190	195	20	20	20	20	20	20	20	201	140	2857
2.22	190	190	200	200	200	120	185	20	20	20	15	15	152	114	184	356	3213
2.29	190	180	185	185	180	185	195	96	91	28	94	96	105	103	186	613	3826
3.07	185	185	185	185	185	185	185	95	87	87	87	85	82	80	185	603	4429
3.14	195	190	190	190	190	185	185	72	72	66	62	68	69	57	189	466	4895
3.21	185	185	185	185	185	190	185	60	58	25	44	67	64	63	186	381	5276
3.28	185	190	190	190	185	185	185	56	55	56	55	53	55	60	187	390	5666
4.04	185	190	185	185	185	190	185	60	63	62	59	55	50	44	186	393	6059
4.11	185	190	190	190	190	190	190	39	48	46	45	46	48	49	189	321	6380
4.18	190	190	190	185	180	185	185	46	43	41	25	37	41	43	186	276	6656
4.25	190	185	190	190	185	185	190	46	44	46	45	45	48	47	188	321	6977
5.02	185	185	185	190	185	185	185	43	40	36	35	29	31	31	186	245	7222
5.09	195	180	185	185	190	190	190	36	36	37	35	36	35	35	188	250	7472
5.16	190	185	190	190	185	190	185	31	31	40	40	39	40	37	188	258	7730
5.23	190	185	190	190	180	180	190	34	29	30	30	33	153	154	186	463	8193
5.30	195	190	190	190	190	185	190	150	136	131	123	122	121	111	190	894	9087

TABLE G6
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-108

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	10	20	60	90	0	0	119	101	94	92	58	36	464	464
11.23	95	175	190	190	190	190	190	69	58	55	44	36	32	30	174	324	788
11.30	190	190	190	190	190	190	190	32	33	29	23	29	33	34	190	213	1001
12.07	190	190	190	190	190	190	195	37	44	46	38	38	40	47	191	290	1291
12.14	190	190	190	200	200	200	200	49	50	51	24	31	36	30	196	271	1562
12.21	205	210	200	200	200	200	200	26	24	20	21	21	21	22	202	155	1717
12.28	200	200	200	170	175	200	200	23	23	26	28	33	42	43	192	218	1935
1.04	200	200	200	200	200	0	0	48	46	31	24	7	0	0	143	156	2091
1.11	0	0	0	0	200	200	200	0	0	0	0	15	10	21	86	46	2137
1.18	200	200	200	200	200	200	200	27	31	31	26	29	26	26	200	196	2333
1.25	200	200	200	200	200	200	200	25	23	26	26	29	27	27	200	183	2516
2.01	200	200	200	200	200	200	200	23	25	25	19	21	26	29	200	168	2684
2.08	200	200	200	200	200	200	200	27	25	27	28	29	25	29	200	190	2874
2.15	200	200	200	200	185	190	195	30	31	34	35	32	31	30	196	223	3097
2.22	190	190	190	190	190	190	190	32	35	33	32	35	34	33	190	234	3331
2.29	190	180	0	120	115	115	125	25	27	0	66	152	151	155	121	576	3907
3.07	125	125	125	130	145	160	175	151	149	143	140	146	138	146	141	1013	4920
3.14	185	190	190	190	190	185	185	137	135	125	118	113	110	102	188	840	5760
3.21	185	185	185	185	185	190	185	105	93	38	79	113	101	95	186	624	6384
3.28	185	185	185	185	185	180	185	96	96	92	86	82	87	94	184	633	7017
4.04	185	185	190	190	185	185	180	95	102	99	88	83	72	70	186	609	7626
4.11	180	185	185	185	190	190	190	61	71	71	69	68	71	73	186	484	8110
4.18	190	190	190	185	185	185	185	71	67	65	65	68	31	74	187	441	8551
4.25	185	185	185	185	180	180	185	78	74	76	73	75	81	78	184	535	9086
5.02	180	185	185	185	180	185	180	73	74	72	69	66	68	67	183	489	9575
5.09	190	175	180	180	190	190	185	70	63	64	59	59	58	51	184	424	9999
5.16	185	185	185	185	185	190	185	53	53	63	62	61	62	60	186	414	10413
5.23	185	185	185	185	180	0	185	54	52	50	50	50	0	139	158	395	10808
5.30	185	155	145	150	140	140	135	179	160	155	148	149	166	156	150	1113	11921

TABLE G7
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-110

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	0	0	0	0	0	126	88	99	143	80	0	536	536
11.23	0	10	45	10	20	20	30	109	113	112	91	103	100	100	19	728	1264
11.30	60	60	70	80	70	70	70	110	109	101	98	99	105	104	69	726	1990
12.07	70	70	80	80	80	85	90	102	103	107	100	98	100	102	79	712	2702
12.14	90	90	90	90	100	100	100	99	99	99	57	98	102	92	94	646	3348
12.21	100	100	100	125	125	125	125	95	92	102	102	97	96	98	114	682	4030
12.28	125	125	125	130	130	165	165	101	99	98	91	90	106	102	138	687	4717
1.04	165	165	165	190	200	200	200	100	96	88	78	62	54	54	184	532	5249
1.11	200	200	200	200	200	200	200	51	54	57	54	53	57	62	200	388	5637
1.18	200	200	200	200	200	200	200	60	59	61	48	50	59	58	200	395	6032
1.25	195	195	195	0	0	0	0	59	60	62	34	0	0	0	84	215	6247
2.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6247
2.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6247
2.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6247
2.22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6247
2.29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6247
3.07	0	0	0	0	185	60	60	0	0	0	98	130	165	155	44	548	6795
3.14	75	60	70	75	75	55	125	175	158	147	173	152	158	154	76	1117	7912
3.21	110	105	10	105	95	105	85	155	154	70	138	147	145	146	88	955	8867
3.28	90	90	90	85	85	85	80	142	143	143	141	140	149	153	86	1011	9878
4.04	80	80	85	85	85	85	85	153	155	157	152	153	152	154	84	1076	10954
4.11	90	80	90	90	100	90	85	145	158	151	145	145	149	148	89	1041	11995
4.18	80	80	80	95	95	95	95	148	147	148	83	152	144	144	89	966	12961
4.25	100	105	105	110	110	110	115	144	146	150	146	152	157	155	108	1050	14011
5.02	115	120	115	130	125	125	125	153	151	147	141	139	139	138	122	1008	15019
5.09	145	130	140	140	150	160	150	147	145	147	144	149	149	150	145	1031	16050
5.16	150	150	150	150	150	150	150	143	143	145	141	146	148	147	150	1013	17063
5.23	155	165	165	175	170	175	185	141	145	159	159	152	142	131	170	1029	18092
5.30	185	190	190	195	190	190	190	122	124	123	118	124	122	102	190	835	18927

TABLE G8
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-116

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	0	10	60	0	0	130	89	102	101	55	14	477	477
11.23	95	145	197	190	190	190	190	92	77	54	41	37	38	33	171	372	849
11.30	190	190	190	190	190	190	190	29	29	22	15	18	24	19	190	156	1005
12.07	190	190	180	190	190	190	195	18	20	19	15	17	19	23	189	131	1136
12.14	190	190	190	195	200	195	195	23	23	24	16	21	22	20	194	149	1285
12.21	195	195	195	195	200	200	200	23	21	21	22	21	20	21	197	149	1434
12.28	200	200	210	185	180	200	200	20	20	21	18	18	20	22	196	139	1573
1.04	200	200	200	200	200	0	0	20	17	16	15	3	0	0	143	71	1644
1.11	0	0	0	0	200	200	200	0	0	0	0	35	12	13	86	60	1704
1.18	200	200	200	200	200	200	200	16	15	16	14	13	17	18	200	109	1813
1.25	200	200	200	200	200	200	200	18	23	28	33	36	33	40	200	211	2024
2.01	200	200	200	200	200	200	200	31	26	26	20	20	23	25	200	171	2195
2.08	200	200	200	200	200	200	200	23	20	24	25	24	24	22	200	162	2357
2.15	200	200	200	200	185	155	155	27	28	28	27	27	12	110	185	259	2616
2.22	140	140	140	120	130	130	145	165	169	158	140	148	151	152	135	1083	3699
2.29	150	170	170	180	175	180	195	130	142	150	145	142	151	156	174	1016	4715
3.07	185	185	185	180	180	185	185	146	141	135	122	116	99	86	184	845	5560
3.14	190	190	190	190	190	185	185	76	75	70	69	67	67	66	189	490	6050
3.21	185	185	185	185	185	190	185	71	68	27	48	73	69	69	186	425	6475
3.28	185	190	190	190	185	185	185	67	68	68	66	64	65	69	187	467	6942
4.04	185	185	185	100	35	90	90	70	71	37	74	128	152	150	131	682	7624
4.11	80	90	100	95	95	95	100	133	138	146	145	146	147	145	94	1000	8624
4.18	100	105	100	110	115	120	120	142	140	152	124	129	155	151	110	993	9617
4.25	125	120	120	125	125	140	140	151	142	147	145	140	150	155	128	1030	10647
5.02	135	140	140	140	140	140	140	153	151	149	144	141	141	141	139	1020	11667
5.09	150	145	150	150	160	160	160	149	146	147	143	150	149	148	154	1032	12699
5.16	160	160	160	160	160	160	160	149	139	152	149	147	145	141	160	1022	13721
5.23	175	180	160	185	180	180	185	143	141	151	148	137	121	120	178	961	14682
5.30	185	185	185	190	190	185	185	115	110	100	95	91	90	75	186	676	15358

TABLE G9
 RATE, PRESSURE, WEEKLY SUMMARIES,
 AND CUMULATIVE INJECTION DATA FOR
 WELL MP-118

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	0	0	70	0	0	127	102	97	102	99	14	527	527
11.23	100	140	190	190	190	190	190	98	98	82	53	38	34	31	170	434	961
11.30	190	190	190	190	190	190	190	32	30	24	20	33	41	37	190	217	1178
12.07	190	190	190	190	190	190	200	43	44	40	35	34	32	21	191	249	1427
12.14	200	200	200	200	200	200	200	16	17	18	14	19	21	20	200	125	1552
12.21	200	200	200	200	200	200	200	22	21	13	47	53	59	56	200	271	1823
12.28	200	200	200	165	170	200	200	52	49	46	42	41	42	40	191	312	2135
1.04	200	200	200	200	200	200	200	39	37	36	34	33	33	33	200	245	2380
1.11	200	200	200	200	200	200	200	33	33	33	31	30	30	27	200	217	2597
1.18	200	200	200	200	200	200	200	28	28	28	26	25	25	25	200	185	2782
1.25	200	195	200	200	200	200	200	24	24	24	24	24	25	24	199	169	2951
2.01	200	200	200	210	205	205	205	24	23	24	22	22	24	25	204	164	3115
2.08	195	200	200	200	200	200	200	25	26	29	31	32	29	31	199	203	3318
2.15	200	200	200	200	190	195	200	32	32	32	29	29	28	27	198	209	3527
2.22	190	195	195	195	190	190	190	27	29	27	25	27	28	28	192	191	3718
2.29	190	185	190	195	180	190	200	24	24	23	19	17	16	15	190	138	3856
3.07	190	190	190	185	190	190	185	14	13	14	12	5	36	138	189	232	4088
3.14	195	190	190	190	190	185	185	118	98	67	86	98	104	106	189	677	4765
3.21	185	185	185	185	185	190	190	113	109	42	85	113	110	74	186	646	5411
3.28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5411
4.04	0	0	0	0	0	0	185	0	0	0	0	0	0	52	26	52	5463
4.11	185	185	185	190	190	190	190	121	121	42	91	85	81	80	188	621	6084
4.18	190	190	190	190	190	185	190	78	73	76	81	72	62	87	189	529	6613
4.25	190	190	190	190	185	185	190	85	80	82	78	74	76	74	189	549	7162
5.02	185	190	190	190	185	185	185	71	69	62	57	52	52	52	187	415	7577
5.09	195	180	180	180	190	190	190	53	50	56	50	51	50	51	186	361	7938
5.16	190	190	190	190	190	190	190	45	45	57	56	56	56	53	190	368	8306
5.23	190	190	190	185	135	135	140	46	39	19	49	124	145	147	166	569	8875
5.30	145	145	155	160	160	160	160	150	140	146	141	144	146	135	155	1002	9877

TABLE G10
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-120

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	10	20	25	55	70	0	0	121	86	94	95	65	36	461	461
11.23	95	160	200	190	200	200	190	92	81	73	58	45	37	33	176	419	880
11.30	200	200	200	200	200	190	195	33	33	26	25	39	46	44	198	246	1126
12.07	195	0	0	0	0	170	200	50	0	0	0	0	32	53	81	135	1261
12.14	200	200	200	210	210	210	200	49	46	49	34	52	54	57	204	341	1602
12.21	200	200	200	210	210	210	210	64	64	65	90	84	80	73	206	520	2122
12.28	210	210	140	130	190	210	210	68	65	69	69	70	77	83	186	501	2623
1.04	210	210	210	215	215	215	210	82	84	82	70	72	73	78	212	541	3164
1.11	210	210	210	210	215	215	220	94	92	92	92	99	111	109	213	689	3853
1.18	210	210	210	210	210	210	210	111	111	114	106	114	114	110	210	780	4633
1.25	210	210	210	210	210	210	210	108	107	111	116	122	128	124	210	816	5449
2.01	210	120	200	200	200	200	200	106	110	100	96	103	104	106	190	725	6174
2.08	175	170	170	170	170	190	190	93	87	96	93	95	89	98	176	651	6825
2.15	190	200	200	200	190	195	200	88	87	91	84	98	103	103	196	654	7479
2.22	195	195	195	195	190	190	190	93	92	96	99	102	95	103	193	680	8159
2.29	190	190	190	180	190	190	190	94	90	90	89	88	87	87	189	625	8784
3.07	190	190	190	190	175	170	175	85	77	78	36	63	146	136	183	621	9405
3.14	195	195	190	190	190	170	170	123	118	110	133	176	156	154	186	970	10375
3.21	170	175	175	170	155	160	180	155	152	66	128	146	136	148	169	931	11306
3.28	180	180	180	180	180	185	190	147	146	144	134	137	142	145	182	995	12301
4.04	190	190	190	190	190	190	185	145	140	136	129	123	118	126	189	917	13218
4.11	185	190	190	190	190	195	190	116	135	135	126	125	127	122	190	886	14104
4.18	190	190	190	190	185	185	185	120	118	120	98	95	112	109	188	772	14876
4.25	190	190	190	190	185	185	190	106	98	99	96	96	106	103	189	704	15580
5.02	185	185	185	190	185	185	185	101	94	84	73	65	66	65	186	548	16128
5.09	195	180	185	185	190	190	190	63	57	51	49	45	42	40	188	347	16475
5.16	190	190	190	190	190	190	190	40	40	40	40	40	40	40	190	280	16755
5.23	190	190	190	185	180	190	190	40	40	40	159	172	167	154	176	772	17527
5.30	155	155	155	160	160	165	175	154	140	141	140	135	143	146	161	999	18526

TABLE G11
 RATE, PRESSURE, WEEKLY SUMMARIES,
 AND CUMULATIVE INJECTION DATA FOR
 WELL MP-126

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (3BL)	INJ (BBL)
11.16	0	0	0	0	0	10	40	0	0	133	90	97	97	63	10	480	480
11.23	80	160	200	190	190	190	190	92	86	50	43	31	22	20	171	344	824
11.30	190	190	190	190	190	190	190	21	21	18	20	38	74	100	190	292	1116
12.07	180	190	120	130	130	120	140	106	174	56	104	102	101	103	144	746	1862
12.14	145	160	160	140	140	135	140	99	90	101	132	96	101	95	146	714	2576
12.21	140	140	140	140	140	140	140	98	96	105	104	105	105	106	140	719	3295
12.28	140	140	140	130	130	140	140	105	103	103	93	91	111	108	137	714	4009
1.04	140	140	140	140	140	120	125	111	112	113	109	104	106	110	125	765	4774
1.11	125	125	125	110	110	115	110	115	83	83	77	89	91	89	117	627	5401
1.18	110	110	110	95	100	140	140	89	89	69	55	108	118	115	115	643	6044
1.25	145	140	140	140	0	0	0	113	112	116	63	0	0	0	81	404	6448
2.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6448
2.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6448
2.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6448
2.22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6448
2.29	0	0	0	0	0	0	175	0	0	0	0	0	0	69	25	69	6517
3.07	185	185	185	190	190	195	195	124	117	131	137	126	108	100	189	843	7360
3.14	200	200	200	200	200	185	195	94	98	90	85	80	81	73	197	601	7961
3.21	195	185	185	190	200	200	195	67	57	20	43	95	85	79	193	446	8407
3.28	195	200	200	200	195	190	200	72	68	66	63	61	58	59	197	447	8854
4.04	200	200	200	200	195	200	195	60	60	59	64	59	53	50	199	405	9259
4.11	195	200	200	200	200	200	200	46	62	56	45	38	34	30	199	311	9570
4.18	200	200	200	200	190	195	200	26	25	14	37	42	38	30	198	212	9782
4.25	200	190	190	200	190	190	195	27	23	21	19	20	19	34	194	163	9945
5.02	195	195	195	200	195	195	195	35	32	24	22	20	20	21	196	174	10119
5.09	190	195	195	195	190	200	200	25	21	37	31	27	25	23	195	189	10308
5.16	200	200	200	200	115	120	110	17	17	24	6	74	150	157	164	445	10753
5.23	105	130	130	135	140	140	170	138	144	152	146	140	136	146	136	1002	11755
5.30	170	170	180	180	180	180	180	150	143	150	147	149	146	137	177	1022	12777

TABLE G12
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-128

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	15	45	70	0	0	116	89	94	94	67	26	460	460
11.23	70	140	180	190	190	190	190	101	102	101	90	64	36	29	164	523	983
11.30	190	190	190	190	190	190	190	27	26	23	19	19	19	20	190	153	1136
12.07	190	190	190	190	190	190	200	20	20	65	37	44	56	53	191	295	1431
12.14	205	205	200	200	200	200	200	37	35	46	17	16	17	19	201	187	1618
12.21	200	200	200	200	200	200	200	24	23	26	31	33	30	25	200	192	1810
12.28	200	200	205	180	180	200	200	24	26	20	20	23	30	27	195	170	1980
1.04	200	200	200	200	200	200	200	23	20	19	18	18	20	20	200	138	2118
1.11	200	200	200	200	200	200	200	20	18	20	19	17	15	13	200	122	2240
1.18	200	200	200	200	200	200	200	13	15	17	15	19	23	23	200	125	2365
1.25	200	200	200	200	200	200	200	26	30	28	30	32	39	40	200	225	2590
2.01	200	200	200	200	200	200	200	32	54	54	57	80	125	116	200	518	3108
2.08	200	200	200	200	200	200	200	97	89	103	101	101	88	87	200	666	3774
2.15	200	200	200	190	165	165	175	86	85	84	80	83	92	90	185	600	4374
2.22	170	175	175	175	170	170	175	86	87	87	89	88	84	88	173	609	4983
2.29	175	170	175	175	185	190	0	78	77	78	83	94	97	0	153	507	5490
3.07	0	0	125	130	155	175	175	0	0	79	137	122	146	144	109	628	6118
3.14	200	200	200	195	195	190	190	138	135	131	129	125	133	136	196	927	7045
3.21	190	190	190	190	190	195	190	143	138	58	116	163	149	146	191	913	7958
3.28	195	195	195	195	190	190	190	141	145	146	137	141	144	148	193	1002	8960
4.04	190	195	195	195	195	195	190	149	147	145	144	133	124	130	194	972	9932
4.11	190	195	195	195	195	195	195	118	138	144	135	134	131	124	194	924	10856
4.18	195	195	195	190	190	195	195	122	121	122	115	120	115	115	194	830	11686
4.25	195	195	195	195	185	190	195	120	115	110	110	100	106	95	193	756	12442
5.02	190	190	190	195	190	195	190	95	95	95	90	90	90	47	191	602	13044
5.09	190	195	185	185	195	195	195	85	85	85	80	80	80	75	191	570	13614
5.16	195	195	195	195	190	0	190	75	75	75	70	70	0	40	166	405	14019
5.23	180	145	190	130	130	135	150	165	168	195	175	150	144	150	151	1147	15166
5.30	155	155	155	160	160	160	175	154	148	146	139	142	142	148	160	1019	16185

TABLE G13
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-130

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	0	0	25	0	0	117	89	100	99	67	5	472	472
11.23	40	150	195	190	190	190	190	91	92	60	40	32	28	25	164	368	840
11.30	190	190	190	190	190	190	190	26	25	21	19	22	23	22	190	158	998
12.07	190	190	190	190	190	190	195	23	26	29	23	24	21	22	191	168	1166
12.14	195	195	200	200	200	200	200	21	20	21	13	15	14	13	199	117	1283
12.21	200	200	200	200	200	200	200	13	12	13	13	13	13	13	200	90	1373
12.28	200	200	200	200	175	195	195	13	14	15	13	14	15	15	195	99	1472
1.04	195	195	200	200	200	200	200	12	16	15	13	15	14	12	199	97	1569
1.11	200	200	200	200	200	200	200	12	13	15	14	13	12	10	200	89	1658
1.18	200	200	200	200	200	200	200	12	14	11	12	14	10	10	200	83	1741
1.25	200	200	200	200	200	200	200	10	10	11	12	11	12	13	200	79	1820
2.01	200	200	200	200	200	200	200	11	13	13	10	10	13	13	200	83	1903
2.08	200	200	200	200	200	200	200	12	11	11	10	10	9	10	200	73	1976
2.15	200	200	200	200	190	190	195	12	13	13	13	14	12	13	196	90	2066
2.22	190	190	190	190	190	190	190	12	15	14	10	16	15	16	190	98	2164
2.29	190	185	190	0	180	115	135	12	10	2	0	132	154	152	142	462	2626
3.07	130	130	130	110	185	185	185	150	144	151	140	104	132	120	151	941	3567
3.14	165	175	175	190	190	180	185	120	97	98	102	95	89	89	180	690	4257
3.21	185	185	185	185	185	190	185	92	80	28	70	99	94	92	186	555	4812
3.28	190	190	190	190	185	185	185	90	89	88	82	84	84	89	188	606	5418
4.04	185	190	190	190	185	190	185	90	92	92	89	88	81	79	188	611	6029
4.11	185	190	190	190	190	195	190	72	81	81	75	74	74	72	190	529	6558
4.18	190	190	190	185	185	185	185	69	69	69	65	63	68	70	187	473	7031
4.25	190	190	190	190	185	185	190	70	64	66	65	65	71	70	189	471	7502
5.02	185	185	185	190	185	185	185	67	63	57	54	51	51	51	186	394	7896
5.09	195	180	190	190	190	190	190	51	49	55	54	54	55	55	189	373	8269
5.16	190	185	185	190	190	95	75	54	51	23	53	2	69	140	159	392	8661
5.23	45	90	95	95	100	115	140	124	136	149	138	130	142	152	97	971	9632
5.30	150	150	150	150	150	165	165	157	149	144	135	136	145	132	154	998	10630

TABLE G14
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-201

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	50	40	70	90	100	0	0	128	89	109	97	64	70	487	487
11.23	160	180	195	200	200	200	200	88	81	60	54	60	64	78	191	485	972
11.30	190	200	170	170	170	160	155	95	111	109	133	126	109	94	174	777	1749
12.07	180	170	200	170	170	175	210	95	66	101	105	97	104	126	182	694	2443
12.14	210	205	200	210	170	175	175	128	121	105	77	104	101	94	192	730	3173
12.21	170	170	175	170	170	180	180	98	96	104	95	94	95	93	174	675	3848
12.28	180	180	180	180	180	190	190	91	86	87	84	89	104	103	183	644	4492
1.04	190	190	190	220	215	210	215	107	109	104	110	115	120	128	204	793	5285
1.11	215	210	210	170	185	180	175	157	117	120	112	111	113	111	192	841	6126
1.18	170	175	175	160	170	170	170	52	109	107	104	100	99	98	170	669	6795
1.25	170	170	170	0	0	0	0	96	97	97	52	0	0	0	73	342	7137
2.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7137
2.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7137
2.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7137
2.22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7137
2.29	0	0	0	0	0	0	195	0	0	0	0	0	0	71	28	71	7208
3.07	170	190	190	210	210	210	240	129	119	139	141	120	108	132	203	888	8096
3.14	215	200	200	200	200	200	205	113	93	85	82	74	79	86	203	612	8708
3.21	205	200	200	205	200	200	200	85	74	32	100	153	23	84	201	551	9259
3.28	200	205	200	205	200	200	205	81	76	74	67	67	65	65	202	495	9754
4.04	205	200	200	200	200	205	200	65	66	63	61	58	54	38	201	405	10159
4.11	190	205	200	180	170	165	170	20	32	14	50	159	150	148	183	573	10732
4.18	170	170	170	160	160	170	175	145	143	132	138	82	137	141	168	918	11650
4.25	175	185	185	190	185	190	175	138	141	143	141	137	147	141	184	988	12638
5.02	190	200	200	200	190	195	200	144	140	135	129	125	127	125	196	925	13563
5.09	195	190	190	190	195	190	185	121	117	116	116	115	116	112	191	813	14376
5.16	185	190	190	190	195	205	195	115	114	118	114	113	115	106	193	795	15171
5.23	190	195	195	195	195	190	205	102	95	96	94	97	96	101	195	681	15852
5.30	190	190	190	195	190	195	205	93	96	82	83	92	96	92	194	634	16486

TABLE G15
 RATE, PRESSURE, WEEKLY SUMMARIES,
 AND CUMULATIVE INJECTION DATA FOR
 WELL MP-203

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	40	60	90	130	140	0	0	90	93	96	93	64	92	436	436
11.23	180	180	190	190	190	190	195	92	80	49	38	34	31	27	188	351	787
11.30	195	200	200	190	190	190	190	24	22	19	23	26	28	20	194	162	949
12.07	190	190	200	170	170	205	205	18	16	17	14	14	14	16	190	109	1058
12.14	200	200	200	210	210	210	210	17	18	18	12	15	15	15	206	110	1168
12.21	210	210	210	210	200	210	210	15	14	14	12	45	41	38	209	179	1347
12.28	210	210	210	205	205	200	200	36	33	34	34	35	36	37	206	245	1592
1.04	200	200	200	210	210	220	210	37	37	36	29	29	35	36	207	239	1831
1.11	210	210	210	210	210	210	215	36	31	28	29	29	31	29	211	213	2044
1.18	215	215	185	215	220	220	220	29	28	30	24	23	24	25	213	183	2227
1.25	220	215	220	220	220	220	220	25	26	27	27	27	32	33	219	197	2424
2.01	200	220	220	220	220	220	220	29	29	28	24	24	23	22	217	179	2603
2.08	210	210	210	210	210	210	210	22	31	59	60	58	67	65	210	362	2965
2.15	215	215	215	215	200	195	205	71	74	74	70	68	67	68	209	492	3457
2.22	215	220	0	175	185	195	200	70	82	0	125	140	146	152	170	715	4172
2.29	200	195	200	200	200	200	200	152	152	149	154	156	148	137	199	1048	5220
3.07	165	180	180	205	205	205	240	119	114	123	118	97	85	97	197	753	5973
3.14	210	200	200	195	200	195	200	76	66	125	60	53	55	63	200	498	6471
3.21	200	200	200	200	195	195	195	67	58	24	81	81	74	72	198	457	6928
3.28	195	200	200	195	195	195	200	73	75	75	71	77	76	77	197	524	7452
4.04	200	195	200	195	195	200	195	78	81	80	78	74	70	70	197	531	7983
4.11	185	195	200	200	195	195	195	65	70	68	33	44	131	131	195	542	8525
4.18	195	195	195	190	190	195	195	129	131	60	133	133	135	140	194	861	9386
4.25	195	185	185	190	200	185	175	169	155	159	157	153	155	150	188	1098	10484
5.02	185	185	185	185	185	185	185	157	155	153	150	148	151	150	185	1064	11548
5.09	185	185	185	185	195	190	190	148	147	145	142	146	143	138	188	1009	12557
5.16	190	195	195	190	195	205	195	145	142	147	145	146	145	140	195	1010	13567
5.23	190	195	195	190	195	190	205	134	128	127	123	125	124	128	194	889	14456
5.30	185	190	190	195	190	190	210	120	112	105	105	114	114	109	193	779	15235

TABLE G16
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-205

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	10	35	60	0	0	153	96	100	99	67	21	515	515
11.23	85	115	190	195	195	190	190	97	93	80	58	54	53	50	166	485	1000
11.30	190	190	200	190	190	200	200	56	54	45	62	54	59	43	194	373	1373
12.07	190	190	200	200	170	170	170	38	37	0	34	29	16	25	184	179	1552
12.14	200	205	200	205	210	210	210	25	24	24	18	23	23	20	206	157	1709
12.21	210	210	210	210	205	205	205	21	20	22	21	21	19	18	208	142	1851
12.28	205	205	205	205	205	205	205	17	17	17	17	17	17	17	205	119	1970
1.04	205	205	205	210	210	205	205	17	17	16	14	15	15	14	206	108	2078
1.11	205	205	205	210	210	210	210	14	13	13	14	14	15	15	208	98	2176
1.18	210	210	210	210	215	215	215	14	14	16	15	14	14	13	212	100	2276
1.25	215	215	215	210	210	210	210	14	16	17	17	16	19	17	212	116	2392
2.01	210	210	210	210	210	210	210	15	16	17	15	15	15	16	210	109	2501
2.08	210	210	210	210	210	210	210	16	18	16	16	17	13	13	210	109	2610
2.15	210	210	210	210	195	195	185	14	16	18	18	17	16	0	202	99	2709
2.22	165	185	185	185	150	170	180	161	151	191	155	156	150	162	174	1126	3835
2.29	180	175	180	180	180	180	180	152	153	149	153	153	144	135	179	1039	4874
3.07	160	180	200	205	190	185	120	123	113	126	123	120	115	114	177	834	5708
3.14	205	195	200	190	195	195	200	113	112	111	110	109	108	107	197	770	6478
3.21	200	200	200	195	195	190	195	104	70	103	102	100	93	89	196	661	7139
3.28	195	195	195	195	195	190	195	87	88	90	88	91	91	95	194	630	7769
4.04	195	195	195	195	195	195	190	95	102	99	97	95	87	88	194	663	8432
4.11	180	195	195	195	195	195	195	83	93	91	86	84	75	75	193	587	9019
4.18	195	195	195	195	200	200	195	73	71	74	74	43	68	67	196	470	9489
4.25	195	195	195	200	195	195	185	63	62	62	60	59	68	64	194	438	9927
5.02	195	195	195	195	195	195	195	64	60	57	55	54	57	57	195	404	10331
5.09	195	190	195	190	195	190	190	54	50	52	56	51	49	47	192	359	10690
5.16	190	195	195	190	195	210	200	47	48	52	53	53	57	50	196	360	11050
5.23	190	195	195	195	195	195	205	46	41	41	38	36	21	6	196	229	11279
5.30	185	190	190	190	190	165	170	20	120	135	142	151	151	150	183	869	12148

TABLE G17
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-211

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	100	50	150	0	0	96	87	88	93	77	60	441	441
11.23	160	170	190	190	200	200	190	106	88	73	63	57	52	49	186	488	929
11.30	190	195	195	190	190	190	190	52	46	38	52	59	64	52	191	363	1292
12.07	190	190	200	200	170	180	210	43	38	39	35	25	29	42	191	251	1543
12.14	210	210	200	210	210	210	210	43	54	67	50	85	97	89	209	485	2028
12.21	210	210	210	210	210	210	210	93	90	96	91	100	103	109	210	682	2710
12.28	210	210	210	205	200	210	210	111	101	101	103	116	120	125	208	777	3487
1.04	205	205	205	140	190	150	150	136	146	118	89	106	114	100	178	809	4296
1.11	150	150	150	150	150	150	165	99	95	99	92	98	102	101	152	686	4982
1.18	180	165	165	170	185	185	185	59	101	94	92	100	104	104	176	654	5636
1.25	180	180	180	0	0	0	0	103	106	108	59	0	0	0	77	376	6012
2.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6012
2.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6012
2.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6012
2.22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6012
2.29	0	0	0	0	0	0	195	0	0	0	0	0	0	76	28	76	6088
3.07	160	180	190	200	200	200	235	127	110	83	135	109	98	122	195	784	6872
3.14	205	200	200	190	195	195	195	106	83	72	69	59	63	71	197	523	7395
3.21	195	195	195	195	195	190	195	69	55	21	83	75	67	67	194	437	7832
3.28	195	195	195	195	195	190	195	65	58	55	48	50	47	45	194	368	8200
4.04	195	195	195	195	195	195	190	46	47	44	43	42	40	14	194	276	8476
4.11	180	0	195	200	195	195	200	2	0	12	100	121	119	119	166	473	8949
4.18	195	200	200	200	200	200	190	109	103	100	134	141	159	145	198	891	9840
4.25	190	195	195	200	200	200	185	138	140	138	134	131	139	126	195	946	10786
5.02	195	190	190	200	190	200	200	126	38	65	77	47	75	94	195	522	11308
5.09	200	195	195	195	200	190	190	89	83	39	94	89	87	82	195	563	11871
5.16	190	200	200	195	200	210	200	83	83	85	82	80	87	77	199	577	12448
5.23	190	200	200	200	200	200	0	78	76	76	75	79	34	0	170	418	12866
5.30	0	0	0	0	0	200	210	0	0	0	0	0	69	85	59	154	13020

TABLE G18

RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-213 (WITH MP-226)

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	100	140	160	170	165	0	0	92	82	85	75	53	147	387	387
11.23	170	0	0	0	0	0	100	70	0	0	0	0	0	92	39	162	549
11.30	125	145	150	140	150	165	160	98	99	99	86	95	102	101	148	680	1229
12.07	160	160	160	170	140	145	175	100	98	105	119	92	91	97	159	702	1931
12.14	175	175	175	190	195	200	200	93	94	91	66	93	93	82	187	612	2543
12.21	200	200	200	210	205	205	205	84	80	84	81	80	80	73	204	562	3105
12.28	205	205	205	205	200	200	200	71	70	71	69	67	65	64	203	477	3582
1.04	200	200	200	210	210	210	210	63	60	59	48	47	41	49	206	367	3949
1.11	210	210	210	205	205	205	210	54	47	48	48	48	50	50	208	345	4294
1.18	210	210	210	205	210	210	210	48	48	50	48	47	45	45	209	331	4625
1.25	210	205	205	205	0	0	0	46	49	48	27	0	0	0	118	170	4795
2.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4795
2.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4795
2.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4795
2.22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4795
2.29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4795
3.07	0	0	0	210	210	210	210	0	0	0	35	49	16	33	120	133	4928
3.14	210	200	200	195	0	200	200	50	85	94	91	0	60	17	172	397	5325
3.21	200	200	200	200	200	195	195	86	80	40	99	90	88	59	199	542	5867
3.28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5867
4.04	0	0	0	0	0	0	195	0	0	0	0	0	0	39	28	39	5906
4.11	185	200	200	200	200	200	200	71	77	73	87	92	81	83	198	564	6470
4.18	200	200	200	200	200	205	200	79	80	81	74	59	60	69	201	502	6972
4.25	200	200	200	200	200	200	185	66	64	65	65	69	79	78	198	486	7458
5.02	195	195	195	195	195	200	200	82	83	84	83	82	85	82	196	581	8039
5.09	200	195	200	200	200	195	195	84	84	82	80	77	74	73	198	554	8593
5.16	195	200	200	200	200	210	200	78	78	79	77	77	87	86	201	562	9155
5.23	195	200	195	195	200	195	210	82	79	80	79	95	52	20	199	487	9642
5.30	190	195	195	195	195	200	210	102	90	86	85	86	87	87	197	623	10265

TABLE G19
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-215

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	25	55	90	0	0	128	91	96	98	65	34	478	478
11.23	120	150	190	200	200	200	200	92	85	63	45	43	46	42	180	416	894
11.30	200	200	200	200	200	200	200	37	28	25	50	49	49	32	200	270	1164
12.07	195	190	200	200	170	130	210	31	27	32	32	31	31	26	192	210	1374
12.14	210	210	200	210	210	215	215	26	29	33	20	20	20	17	210	165	1539
12.21	210	210	210	210	205	210	210	22	21	18	25	29	27	25	209	167	1706
12.28	210	210	210	210	210	210	210	23	19	22	27	31	31	32	210	185	1891
1.04	210	210	210	215	210	215	215	31	28	26	18	19	23	21	212	166	2057
1.11	215	215	215	220	220	210	215	19	15	13	18	23	22	22	216	132	2189
1.18	215	215	215	210	215	220	220	21	22	25	20	23	22	16	216	149	2338
1.25	215	210	215	215	215	215	215	20	30	32	35	39	42	37	214	235	2573
2.01	215	215	215	220	220	220	210	32	29	29	28	27	27	29	216	201	2774
2.08	210	220	200	210	210	210	210	30	32	19	25	25	26	22	210	179	2953
2.15	215	210	210	210	200	195	205	27	29	33	34	29	23	20	206	195	3148
2.22	220	220	220	220	200	200	200	23	30	26	24	31	32	36	211	202	3350
2.29	0	0	0	0	200	0	80	0	0	0	0	129	0	48	40	177	3527
3.07	75	90	125	135	135	170	180	135	130	152	145	145	145	157	130	1009	4536
3.14	180	190	190	190	195	195	200	141	140	138	135	130	127	131	191	942	5478
3.21	200	200	200	195	195	195	195	136	120	48	138	137	130	128	197	837	6315
3.28	195	195	195	195	195	190	195	128	127	127	123	125	125	126	194	881	7196
4.04	195	195	195	195	195	200	195	126	125	120	116	118	113	112	196	830	8026
4.11	185	195	190	200	195	195	195	99	110	107	102	100	94	94	194	706	8732
4.18	195	200	200	200	200	200	195	92	91	90	89	88	87	85	199	622	9354
4.25	195	195	195	200	200	195	185	84	77	82	80	87	98	98	195	606	9960
5.02	195	190	190	200	190	200	195	104	101	93	88	86	88	86	194	646	10606
5.09	195	195	195	195	195	190	190	84	80	80	80	76	74	72	194	546	11152
5.16	190	195	195	195	195	205	200	75	75	77	76	77	83	81	196	544	11696
5.23	195	195	195	195	195	195	205	82	80	81	79	80	78	79	196	559	12255
5.30	190	195	195	195	195	195	210	73	68	65	64	66	66	37	196	439	12694

TABLE G20
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-221

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	10	15	40	0	0	134	101	102	99	69	13	505	505
11.23	50	65	80	80	90	110	120	102	100	102	91	90	94	89	85	668	1173
11.30	130	160	200	195	190	190	195	97	91	81	87	90	83	56	180	585	1758
12.07	195	190	200	200	170	180	210	52	51	58	56	41	36	51	192	345	2103
12.14	210	210	200	210	210	215	210	45	47	46	32	40	33	27	209	270	2373
12.21	200	200	200	210	205	205	205	35	32	31	37	39	33	26	204	233	2606
12.28	205	205	205	210	205	210	210	25	22	24	24	29	29	29	207	182	2788
1.04	210	210	210	220	215	210	210	28	25	23	23	29	30	25	212	183	2971
1.11	210	210	210	210	210	210	215	21	16	17	22	22	23	22	211	143	3114
1.18	215	215	215	210	210	210	210	21	21	24	26	27	24	20	212	163	3277
1.25	210	210	210	210	210	210	210	24	32	31	33	34	49	55	210	258	3535
2.01	210	210	210	210	210	210	210	60	65	62	56	54	55	57	210	409	3944
2.08	210	210	210	210	210	210	210	56	55	38	35	35	25	24	210	268	4212
2.15	210	210	210	210	210	200	205	28	35	38	39	38	39	39	208	256	4468
2.22	210	210	210	215	200	200	210	43	50	47	45	58	54	60	208	357	4825
2.29	205	200	200	200	0	0	50	56	49	62	24	0	0	135	122	326	5151
3.07	50	70	70	100	105	125	145	150	145	150	152	149	144	159	95	1049	6200
3.14	135	175	175	140	150	150	190	153	145	148	148	151	149	152	159	1046	7246
3.21	175	180	190	195	185	205	180	155	150	68	158	146	143	143	187	963	8209
3.28	190	190	190	185	185	195	190	143	142	142	138	140	146	148	189	999	9208
4.04	190	190	190	205	200	200	200	149	150	147	144	144	142	143	196	1019	10227
4.11	205	200	200	215	215	215	210	131	145	143	136	134	126	126	209	941	11168
4.18	200	200	200	195	200	205	200	138	145	147	96	141	140	137	200	944	12112
4.25	200	195	195	200	200	200	185	132	127	127	122	120	132	123	196	883	12995
5.02	195	195	195	195	195	200	200	130	124	115	109	106	103	97	196	784	13779
5.09	200	195	195	195	200	195	195	94	91	80	80	78	72	70	196	565	14344
5.16	195	200	200	195	200	210	200	73	72	72	66	71	93	78	200	525	14869
5.23	195	200	200	195	200	195	205	75	71	76	68	66	16	56	199	428	15297
5.30	190	195	195	190	195	200	210	80	66	60	60	111	115	104	196	596	15893

TABLE G21

RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-223

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	70	100	120	140	160	0	0	117	95	99	99	65	118	475	475
11.23	180	180	0	0	0	0	0	86	26	0	0	0	0	0	51	112	587
11.30	0	70	80	30	50	95	100	0	108	105	81	69	92	94	61	549	1136
12.07	95	115	130	110	120	130	145	94	94	97	84	86	81	90	121	626	1762
12.14	150	145	150	200	200	200	200	85	89	94	66	91	88	87	178	600	2362
12.21	200	210	200	210	210	200	200	80	74	75	73	74	79	67	204	522	2884
12.28	200	200	200	195	195	195	195	64	61	62	60	59	57	55	197	418	3302
1.04	195	195	195	155	170	205	205	54	50	49	43	51	47	42	189	336	3638
1.11	205	205	205	200	200	200	190	40	35	36	39	40	41	40	201	271	3909
1.18	190	190	190	190	190	190	190	39	38	32	49	39	36	36	190	269	4178
1.25	190	200	200	200	200	200	200	38	40	40	26	7	6	3	199	160	4338
2.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4338
2.08	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4338
2.15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4338
2.22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4338
2.29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4338
3.07	165	185	180	200	200	205	205	60	146	130	139	132	122	131	191	860	5198
3.14	210	195	200	195	195	195	200	112	102	98	97	93	91	96	199	689	5887
3.21	200	200	200	200	195	195	195	98	88	34	97	98	95	92	198	602	6489
3.28	200	200	200	200	195	195	200	94	94	95	92	94	92	92	199	653	7142
4.04	200	195	195	195	195	200	195	92	92	91	92	94	93	92	196	646	7788
4.11	185	195	195	200	195	195	200	81	86	85	84	54	65	65	195	520	8308
4.18	205	200	200	195	200	205	200	89	88	89	83	83	80	78	201	590	8898
4.25	200	195	195	200	200	200	190	77	74	74	73	75	80	79	197	532	9430
5.02	195	195	195	200	195	200	200	81	80	79	77	77	78	78	197	550	9980
5.09	200	195	195	195	200	190	190	77	76	75	74	73	73	72	195	520	10500
5.16	190	200	200	195	200	210	200	74	71	74	72	72	76	74	199	513	11013
5.23	195	195	195	200	200	195	205	74	72	73	73	73	72	73	198	510	11523
5.30	190	190	190	195	0	195	210	71	68	68	68	0	75	68	167	418	11941

TABLE G22
RATE, PRESSURE, WEEKLY SUMMARIES,
AND CUMULATIVE INJECTION DATA FOR
WELL MP-225

DATE MONTH, DAY	P R E S S U R E (PSIG)							R A T E (BBL/D)							WEEKLY SUMMARY		CUMULATIVE
	S	M	T	W	T	F	S	S	M	T	W	T	F	S	P (PSIG)	INJ (BBL)	INJ (BBL)
11.16	0	0	0	0	20	45	20	0	0	96	93	101	99	55	17	444	444
11.23	55	100	120	150	160	170	200	83	95	93	86	83	84	80	136	604	1048
11.30	190	200	200	180	190	200	195	75	61	47	69	63	71	50	194	436	1484
12.07	190	190	200	200	175	175	210	54	45	43	50	39	38	41	191	310	1794
12.14	210	200	200	210	210	215	210	40	40	39	27	38	36	29	208	249	2043
12.21	210	210	210	210	210	210	210	34	31	32	33	35	35	33	210	233	2276
12.28	210	210	210	210	205	210	210	31	29	31	30	32	39	31	209	223	2499
1.04	210	210	210	210	210	215	215	30	29	28	24	31	31	27	211	200	2699
1.11	215	215	215	220	210	210	210	25	20	20	24	26	27	27	214	169	2868
1.18	210	210	210	210	215	215	215	26	25	28	29	29	27	24	212	188	3056
1.25	215	215	215	215	215	215	215	26	31	31	32	32	38	36	215	226	3282
2.01	215	215	215	215	215	215	215	35	39	39	36	34	33	34	215	250	3532
2.08	215	215	215	215	215	215	215	33	36	30	31	30	29	25	215	214	3746
2.15	215	215	215	215	215	200	215	29	32	32	32	31	29	26	213	211	3957
2.22	225	225	225	225	215	215	215	31	38	35	31	40	39	42	221	256	4213
2.29	200	215	215	215	0	0	210	42	44	37	35	0	0	72	151	230	4443
3.07	160	195	195	215	210	210	210	102	148	150	146	136	131	142	199	955	5398
3.14	220	200	200	200	210	205	210	124	115	110	109	104	100	105	206	767	6165
3.21	210	210	200	210	205	205	210	109	89	28	107	108	103	103	207	647	6812
3.28	210	210	210	210	210	205	210	103	102	102	99	101	100	100	209	707	7519
4.04	210	210	210	210	210	210	200	101	101	98	97	97	95	94	209	683	8202
4.11	195	210	200	210	210	210	210	84	94	92	88	88	86	86	206	618	8820
4.18	210	210	210	210	215	220	210	85	85	86	52	74	73	67	212	522	9342
4.25	210	210	210	210	210	210	200	11	55	81	81	88	97	96	209	509	9851
5.02	210	210	210	210	210	210	210	101	101	96	93	91	93	92	210	667	10518
5.09	210	210	210	205	115	0	0	89	86	84	84	58	0	0	136	401	10919
5.16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10919
5.23	0	0	0	180	0	0	0	0	0	0	11	0	0	0	26	11	10930
5.30	0	0	0	0	0	0	220	0	0	0	0	0	0	0	31	0	10930

TABLE G23
EL DORADO PROJECT OBSERVATION WELL DATA

Well No.	Surface Casing (8 5/8 in)		Production Casing** (5 1/2 in)		Location	Completion Date	Top of Sand, ft	Datum* feet	Gross Thickness feet	Total Depth feet	Perforated Completion Interval, ft
	Depth feet	Cement yard	Depth feet	Cement No. of sacks							
MP-131	27	1	701	175	992' FSL, 2576' FWL Sec. 21-25S-5E	3/22/76	636	761	22	704	644-645
MP-132	29	1	706	175	924' FSL, 2508' FWL Sec. 21-25S-5E	3/26/76	641	752	21	710	645-646
MP-227	29	1	717	175	592' FNL, 2576' FWL Sec. 28-25S-5E	3/19/76	664	737	19	718	668-669
MP-228	27	1	713	175	660' FNL, 2508' FWL Sec. 28-25S-5E	4/4/76	659	741	19	717	665-666

*Datum above mean sea level

**Steel casing run with three joints fiberglass casing on bottom

TABLE G24

TYPICAL MILLIPORE FILTER RESIDUE ANALYSES AT VARIOUS TIMES AND LOCATIONS

	<u>Pretreatment Fluid</u>	<u>Filtered Fresh Water</u>	<u>Wellhead Sample MP-120</u>	<u>North Pattern Tank Mixture</u>	<u>Saturated Salt Water</u>	<u>Filtered Fresh Water</u>	<u>Filtered Fresh Water</u>	<u>Raw El Dorado Lake Water</u>
Date	11/28/75	12/10/75	12/11/75	12/11/75	12/13/75	2/3/76	2/19/76	2/19/76
Total Solids, mg/l	51	0.6	7	9	67	0.43	0.3	11.0
Organics, mg/l	16	0.4	3	5	3	0.13	0.05	5.0
Iron Oxide, mg/l	13	trace	1	0.1	1	0.03	0.02	0.4
Calcium Carbonate, mg/l	4	trace	trace	0.1	2	0.01	0.01	trace
Silica, mg/l	0	0.1	0.1	0.1	0.2	0.13	0.04	4.4
Barium Sulfate, mg/l	16	0	0	0	0	0	0	0
Others, mg/l	2	0.1	3	4	61	0.13	0.18	1.2

FIGURE G-1

INJECTION RATE AND CUMULATIVE VOLUME VERSUS

TIME FOR CHESNEY PATTERN

----- INJECTION RATE

----- CUMULATIVE INJECTION

FIGURE G-2.

INJECTION RATE AND CUMULATIVE VOLUME VERSUS
TIME FOR HEGBERG PATTERN.

FIGURE G-3

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-106

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-4

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-108

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-5

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-110

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-6

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-116

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-7

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-118

——— PRESSURE
 - - - - - INJECTION RATE
 - - - - - CUMULATIVE INJECTION

FIGURE G-8

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-120

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-9

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-126

PRESSURE

INJECTION RATE

CUMULATIVE INJECTION

FIGURE G-10

INJECTION RATE, PRESSURE, AND CUMULATIVE
VOLUME INJECTED VERSUS TIME FOR
WELL MP-128

— PRESSURE
- - - INJECTION RATE
- - - CUMULATIVE INJECTION

FIGURE G-11

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-130

— PRESSURE

- - - INJECTION RATE

- - - CUMULATIVE INJECTION

FIGURE G-12

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-201

PRESSURE

INJECTION RATE

CUMULATIVE INJECTION

FIGURE G-13

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-203

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-14

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-205

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-15

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-211

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-16

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-213 (WITH MP-226)

PRESSURE

INJECTION RATE

CUMULATIVE INJECTION

FIGURE G-17

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-215.

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-18

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-221

FIGURE G-19

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-223

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-20

INJECTION RATE, PRESSURE, AND CUMULATIVE

VOLUME INJECTED VERSUS TIME FOR

WELL MP-225

— PRESSURE
 - - - INJECTION RATE
 - - - CUMULATIVE INJECTION

FIGURE G-21

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-106

FIGURE G-22

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-108

FIGURE G-23

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-110

FIGURE G-24

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-116

FIGURE G-25

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-118

FIGURE G-26

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-120

B - Broken sand or shale

FIGURE G-27

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-126

FIGURE G-28

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-128

FIGURE G-29

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-130

FIGURE G-30

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-201

FIGURE G-31

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-203

FIGURE G-32

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-205

B - Broken sand or shale

FIGURE G-33

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-211

FIGURE G-34

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-213

100% of the flow went below 658 feet,
the deepest point reached with the
tool.

FIGURE G-35

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-215

FIGURE G-36

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-221

FIGURE G-37

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-223

FIGURE G-39 PROJECT LAYOUT

FIGURE G-38

INJECTION AND PERMEABILITY PROFILE FOR WELL MP-225